JPL PUBLICATION 81-20

DOE/ET-29372-1
Distribution Category UC-97C

(NASA-CR-164700) CONCEPTS FOR DESIGN OF AN ENERGY MANAGEMENT SYSTEM INCORPORATING DISPERSED STORAGE AND GENERATION (Jet Propulsion Lab.) 135 p HC A07/MF A01 CSCL 10B G3/44

N81-30560

Unclas 27243

Concepts for Design of an Energy Management System Incorporating Dispersed Storage and Generation

H. Kirkham
T. Koerner
D. Nightingale

April 15, 1981

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

JPL PUBLICATION 81-20

DOE/ET-29372-1
Distribution Category UC-97C

Concepts for Design of an Energy Management System Incorporating Dispersed Storage and Generation

H. Kirkham
T. Koerner
D. Nightingale

April 15, 1981

Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy through an agreement with the National Aeronautics and Space Administration.

ABSTRACT

New forms of generation based on renewable resources must be managed as part of existing power systems in order to be utilized with maximum effectiveness. Many of these generators are by their very nature dispersed or small, so that they will be connected to the distribution part of the power system. This situation poses new questions of control and protection, and the intermittent nature of some of the energy sources poses problems of scheduling and dispatch. This report assumes that the general objectives of energy management will remain unchanged. and discusses the impact of dispersed storage and generation on some of the specific functions of power system control, and its hardware.

PREFACE

This report was written in 1980 as part of JPL's Communication and Control for Electric Power Systems Project, sponsored by the Office of Electric Energy Systems of the United States Department of Energy. As far as the control side of the project was concerned, this represents one of three major tasks of that project during 1980. The other two were (1) a study of the control and monitoring requirements of dispersed storage and generation, which was performed under contract by the General Electric Company and (2) the development of a statement of work for a task to be executed during 1981 extending the present work to include impacts other than those of Dispersed Storage and Generation (DSG).

The task represented in this report was therefore clearly the major in-house effort on the Communication and Control Project. There were really two objectives of the task: first to provide a foundation for a genuine advance in the state of the art of power system operation with DSG; second to be a medium by which some of the workers at JPL could gain additional experience and knowledge in the area of power system operation and control. Perhaps both of these objectives have been met. A third objective emerged as the work progressed, namely it became clear that this report could serve as ground work for many 1981 tasks in the Communication and Control Project. Consequently, during the latter part of 1980, some effort was devoted to laying a solid foundation for the follow up tasks of modular design of DSG controllers and the functional aspects of the substation controller. The bulk of this work is to be found in Section 4 of this report.

The work on this task was a learning experience for many of the participants. As a result, the document should be useful to engineers with or without a good background in power systems. This report will be found to contain a good deal of tutorial and background material, in addition to the new work on DSG control. The combination of this report and the report prepared by General Electric on the Monitoring and Control Requirements for DSG provides a comprehensive set of background information for engineers in utilities, manufacturers and research organizations.

H.K.

CONTENTS

Figures

Tables

EXECUTIVE SUMMARY

A. INTRODUCTION

A variety of factors, particularly the rising cost of oil, has encouraged the development of new sources of electrical energy, many of them using renewable resources. The percentage of demand presently met by these generators is small. It seems inevitable, however, that as their penetration level increases, the need to manage them as an integrated part of the power system will become increasingly evident.

This report presents an overview of the design of an energy management system (EMS) incorporating dispersed storage and generation (DSG). The work reviews the functions of energy management, and examines the impact of dispersed storage and generation on those functions and their implementation.

The penetration of dispersed storage and generation into the power system is, at present, rather small. Many of the questions raised regarding DSG integration can only be answered speculatively. It is important, however, to raise these questions even if a satisfactory and unequivocal answer cannot now be given, in the hope that new solutions to these new problems will be found. Perhaps this report will encourage work that will facilitate the incorporation of DSGs into the planning, construction, and operation activities of future electric utilities.

B. DISCUSSION OF AN ENERGY MANAGEMENT SYSTEM AND AN ENERGY CONTROL CENTER

For the purposes of this report, an EMS is defined as a collection of control strategies and operational practices, together with the hardware and software to accomplish the objectives of energy management. An EMS includes the acquisition of data for control, and the furnishing of information for planning and design. It takes into account those institutional issues which affect decision making, the provision of reserve margins, and other policies and procedures. This very broad description of an energy management system would include protection, although the hardware which performs the protection functions is separate from the normal control hardware, and usually operates locally.

The real-time activities of an EMS occur in the Energy Control Center (ECC) and ensure that a reliable supply of electric power is delivered to the customer at minimum system operating cost. This means that the operating frequency and voltages must be at the proper values, and the power flow between areas must be controlled to meet contractual agreements with other systems. The capability is required to record data which confirm normal system operation, provide diagnostic information in the event of system abnormalities, and substantiate power and energy flows to other systems.

C. WHAT IS DSG?

Over the last decade or so, there has been an increase in activity devoted to the development of renewable resources for generating electric energy. Many of these generators are small and can only be economically connected to the distribution system or to the subtransmission system. Those which involve storage, a secondary source of energy, can provide a means to achieve more efficient use of existing generating plant.

The list of DSG given below includes some indication of the potential for assisting with the electrical energy needs of the nation.

(1) Hydroelectric: the economies of scale are such that relatively small hydro-generators are economical. The technology is already developed.

(2) Solar Thermal Electric: a wide range of power levels and equipment types can use this approach; however, the method is not at present fully commercialized.

(3) Photovoltaics: photovoltaic cells produce direct current which varies with insolation. The cell voltage varies slightly with temperature. A convertor is required to convert the dc to ac for connection to the distribution system.

(4) Wind: wind systems may consist of one or more moderate size units (200 kW to 3 MW). Because wind is not generally a steady resource, systems presently are only economical in limited applications.

(5) Storage Battery: storage batteries are not true sources of electrical power. However, storage in general improves the utility load factor and may reduce the net cost of energy by improving the utilization of existing equipment.

(6) Hydroelectric Pumped Storage: economies of scale have favored large installations, but smaller ones (of only a few megawatts) are under active consideration.

(7) Co-generation: co-generation employs fully developed technology and is of immediate economic benefit. It must be considered in any discussion of DSG.

D. IMPACT OF DISPERSED STORAGE AND GENERATION

To understand more clearly the impact of dispersed storage and generation, it is best to separate the attributes of DSGs into two major groups. First, those that will influence the real-time control of the power system and interact with system related factors. Second, attributes that will influence only the longer term operation of the system and interact with institutional, political or environmental attributes of the power system.

1. DSG Factors Which Influence Real-Time Control

(1) Size or power capability determines where in the distribution system the DSG will be connected. Size will also affect the amount of utility control.

(2) Power source availability and stability strongly affect the use and scheduling of a DSG unit. Rapid change in power flow because of wind gusts or broken cloudiness could require additional control.

(3) Capability for DSG voltage control can assist in local line voltage control. In some cases, reactive power flow control can be provided as well.

(4) Time-response characteristics allow a DSG, responding rapidly to signals, to help stabilize a situation in which other DSG sources are varying.

(5) Harmonic generation from a DSG is a source of possible interference. Internal or external filtering of the DSG unit may be required to make a DSG acceptable for connection to a utility.

(6) Automatic start capability on a DSG enhances its usability; it can be controlled from an ECC without an operator. Automatic start here includes start-up and acceleration if applicable, synchronization and connection to the system.

(7) Special requirements such as azimuth control on wind units and solar tracking for some photovoltaic arrays.

In addition to these factors, there are some overall system considerations when a DSG is connected. Islanding, the process of splitting a large power network into two or more smaller networks during an outage, can significantly affect the control of DSG. The possibility of islanding must be provided for in the design of EMS for integrated DSG operation.

Table ES-1 shows the interactions between the DSG factors listed above and the EMS or ECC functions. The table is a matrix of interactions that was constructed subjectively. EMS functions can be compared to see which are most impacted by integration of DSG.

Protection of the system is an especially important function of energy management and is affected by interaction with most of the DSG factors listed. Many of the DSGs that could be put on the distribution system will not provide overcurrent in the event of a short-circuit. Because the control systems of such DSGs are non-linear, some devices would continue to feed rated current only into a short circuit. Fuses would not blow, overcurrent relays would not pick up. The system voltage would be low but distribution system protection is not often based on voltage (or impedance) information. If a fault occurs and the fuses blow between the fault and the incoming power system, a DSG might keep the system energized at low voltage. The low voltage would not harm the DSG; in fact, it might burn the fault clear. Most utilities, however, would try to avoid this condition because of possible consumer equipment damage.

Table ES-1. Interactions between DSG Factors and EMS Functions

FACTORS / FUNCTIONS	Size	Power Source Availability	Power Source Stability	Energy Limitation	DSG Voltage Control	Response Speed	Harmonic Generation	Automatic Start	Special DSG Factors
Automatic Gen. Control	1	1	1	0	1	0	1	0	1
Economic Dispatch	1	1	1	?	0	0	1	0	?
Auto. Voltage Control	1	0	1	1	1	?	0	0	?
Protection	1	0	1	1	1	1	1	1	1
State Estimation	1	0	0	0	0	0	?	0	1
On-Line Load Flow	1	0	0	0	0	0	0	0	1
Security Monitoring	1	0	0	0	0	0	0	0	1
Security Analysis	1	1	?	0	0	0	1	0	1
Auto. System Trouble Anal.	0	0	0	0	0	0	0	0	0
Emergency Control	0	0	?	0	0	0	0	1	1
Auto. Circuit Restoration	0	0	0	0	0	0	0	0	0

1 - interaction probable 0 - interaction unlikely
? - interaction possible

2. DSG Factors Affecting Long-Term Aspects of Energy Management

(1) Lack of standardization, especially of small, residential size units is apparent. Standardization of physical connections, of voltage levels and type of connection, and quality standards for the various signals (including the ac power itself) are all required. The protection system should also be standardized, although not necessarily identical for all DSGs. An inspector instead of an engineer could then provide approval for connection of the DSG to the utility system.

(2) Legal problems on consumer ownership of utility connected generation and the question of buy-back rates need resolution. Other issues of concern include maintenance and environmental impact.

(3) It may be necessary to create special groups within the utility to approve DSG interconnection, settle rate and maintenance questions, and participate in zoning and environmental hearings. This need may be great towards the end of the century when the number of DSGs is expected to rise rapidly.

3. Hardware Impacts

The integration of DSGs will have additional impacts on energy management unctions, leading to some hardware changes. The obvious changes are to the protection system and to the communication system for proper control over remote DSGs. Further, because of the large number of DSGs required for significant impact and their dispersed nature, a maximum amount of distributed intelligence with a control hierarchy will probably be used. A recent report considered controlling DSGs with a system of three or four levels. The top level is the central ECC and the lowest level is the DSG controller. One or two levels are between these. Figure ES-1 shows this arrangement and indicates the parallel structure that can be expected between the power system and the control system hierarchies. The power system hierarchy and the top of the control system hierarchy already exist. The rest of the control hierarchy in this figure is one of a number of possible future hierarchies. A level of control is located at the distribution substation as shown. Control exercised from here is of two types: control using local intelligence only and control based on inputs from a higher authority within the control structure. Probably, most controlled hardware will operate on a priority system that establishes whether local control acts alone or in accordance with centrally-computed instructions.

In a system with distributed intelligence, two important control system features, information processing and decision making, may be locally situated or centrally located. The central controller, located at the ECC, has information available to it concerning the entire system. It can process this information and issue commands based on its decisions. The local controller has available to it local information not available at ECC. Its decisions reflect local conditions.

The highest priority need not always be at the highest level in the control structure; a properly coordinated system would permit the substation controller to recognize local constraints or requirements. For example, there might be a life-support system on a feeder. Local knowledge of DSGs is essential for effective coordination. Little is gained by controlling DSGs from a more remote location than the closest distribution substation.

The controller at the substation is doing two things. First, it is controlling and monitoring local hardware using local information. To do this, it must interact with a variety of switches and regulators and must interact with DSGs (if controllable) connected at the substation level or below. Second, the substation controller must interact with the next highest level in the control hierarchy, process its commands and (if appropriate) pass the information to the devices in its area.

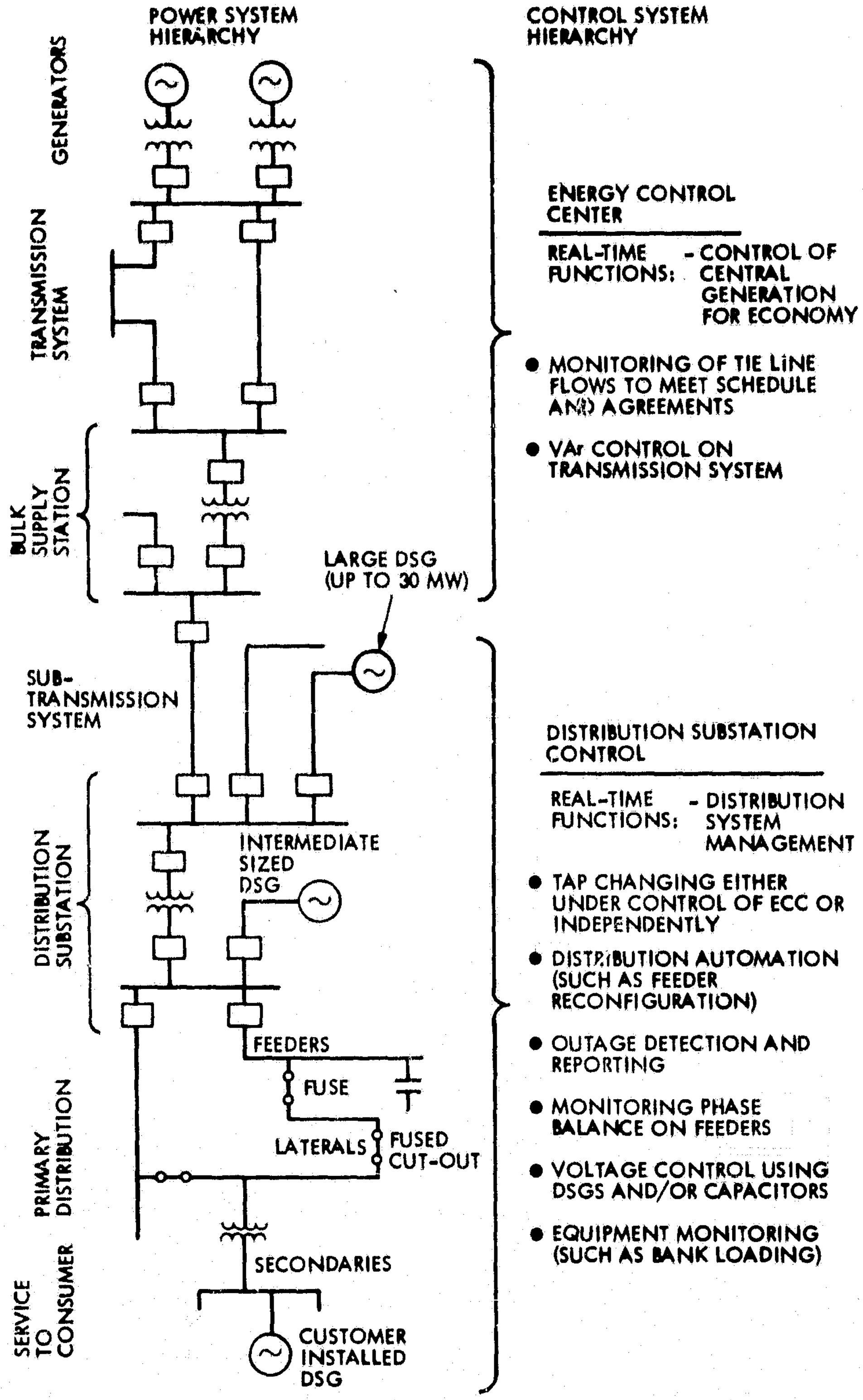


Figure ES-1. Simplified Power System, Showing Possible Parallel with Control System Hierarchy

The information "passed through" a distribution substation controller can be modified considerably by the controller in the process. For example, the signal from the ECC might be a bit-string representing the command "decrease load one notch". The result could be a tap-change operation, an increase in output from some DSGs, or limited load shedding. With the system shown in Figure ES-1, each distribution substation within the ECC control area would make its own decision on how to implement the original instruction. A configuration in which the control system essentially parallels the power system in this way is worthy of further study. This approach would minimize inter-level communications and provide for more effective system operation in the case of temporary communications problems. Figure ES-2 summarizes this discussion.

E. CONCLUSIONS

The integration of dispersed storage and generation into the power system does not seem inconsistent with the objectives or functions of energy management. It can have benefits besides the obvious one of supplying electrical demand from renewable resources. The possibility also exists that DSGs can be used as load followers, reducing the expense of load-following with fossil units. It is also possible that DSG, because it is dispersed, can help control loading of individual transmission lines. These benefits do not come free. To be effectively integrated, a large number of DSG units must be controlled in a coordinated fashion. This requirement necessitates some changes to the software functions carried out at the control center and careful coordination of system and DSG protection. A control hierarchy using an intelligent device at the distribution substation has many advantages. DSG voltage control may provide a method of local voltage regulation to complement existing methods. Assistance with system VAR generation may also be possible.

Some long-term aspects of energy management are impacted by DSG. It may eventually be necessary for utilities to form special groups to handle DSG questions such as installation approval for customer owned DSGs, rate setting and maintenance agreements. The utilities may also face a formidable problem unless the siting approval process is simplified for a utility-owned DSG.

Many problems presented in this report will be simplified by standardizing unit sizes, and interfaces, although such a step requires action outside the utility industry. Suitable standards and definitions are required if DSG energy is to play its maximum part in supplying national energy needs.

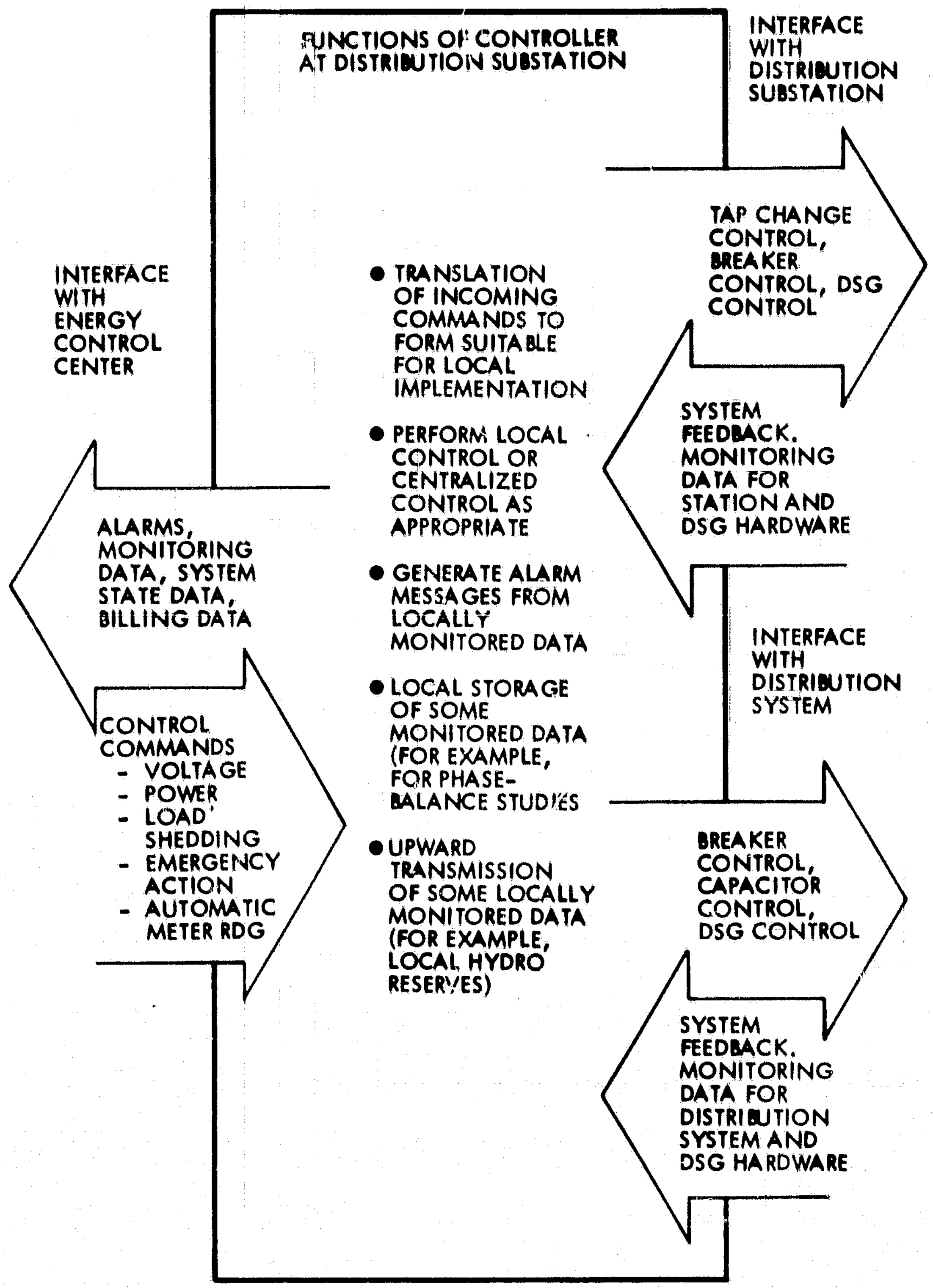


Figure ES-2. Functions and Interfaces of a Controller at the Distribution Substation

SECTION I
ENERGY MANAGEMENT SYSTEMS

A. INTRODUCTION

Because in a modern electric utility most electricity is generated in large central station generators, energy management is implemented in a centralized manner. That is to say, most aspects of control, monitoring and computation are performed at a single location for an entire utility. An energy management system (EMS) is defined as a collection of control strategies and operational practices together with the hardware and software to accomplish the objectives of energy management. An EMS includes the acquisition of data for control and the furnishing of information for planning and design. It takes into account those institutional issues which affect decision making, the provision of reserve margins, and other policies and procedures. This very broad description of an energy management system would include protection, even though the hardware which performs the protection functions is separate from the normal control hardware, and usually operates locally.

The real-time activities of an EMS occur in the energy control center (ECC) and ensure that a reliable supply of electric power is delivered to the customer at minimum system operating cost. This means that the operating frequency and voltages must be at their proper values, and the power flow between areas must be controlled to meet contractual agreements with other systems. The capability is required to record data which confirm normal system operation, provide diagnostic information in the event of system abnormalities, and substantiate power and energy flows to other systems.

Figure 1-1 shows that the energy control center is, in any case, part of a real-time control hierarchy even at today's stage of development. Even if an electric utility is fairly large and makes a significant investment in a modern computerized control center, it is still prudent for that utility to be aware of the actions of the neighboring utilities. This requires information from the energy control centers in charge of those neighboring companies. The advantages are obvious: by being aware of the condition of the neighboring system, the utilities can coordinate their system operation so that the total spinning reserve, for example, is reduced, or so that from time to time judicious purchases of relatively inexpensive electricity are made. Intercompany exchange of capacity or energy can be made on a scheduled or emergency basis and generally works to the advantage of both companies.

At the lower levels in the hierarchy, the energy control center generally has real-time control over the major switching stations, substations and generators within its control area. This is usually accomplished by means of a supervisory control and data acquisition system (SCADA). Of course, the degree of sophistication of the real-time control exercised through the SCADA system varies from company to company, and even within a company. In some of the older generating stations, for example, control of real and reactive power is purely a local function, and the control of these two parameters may not even

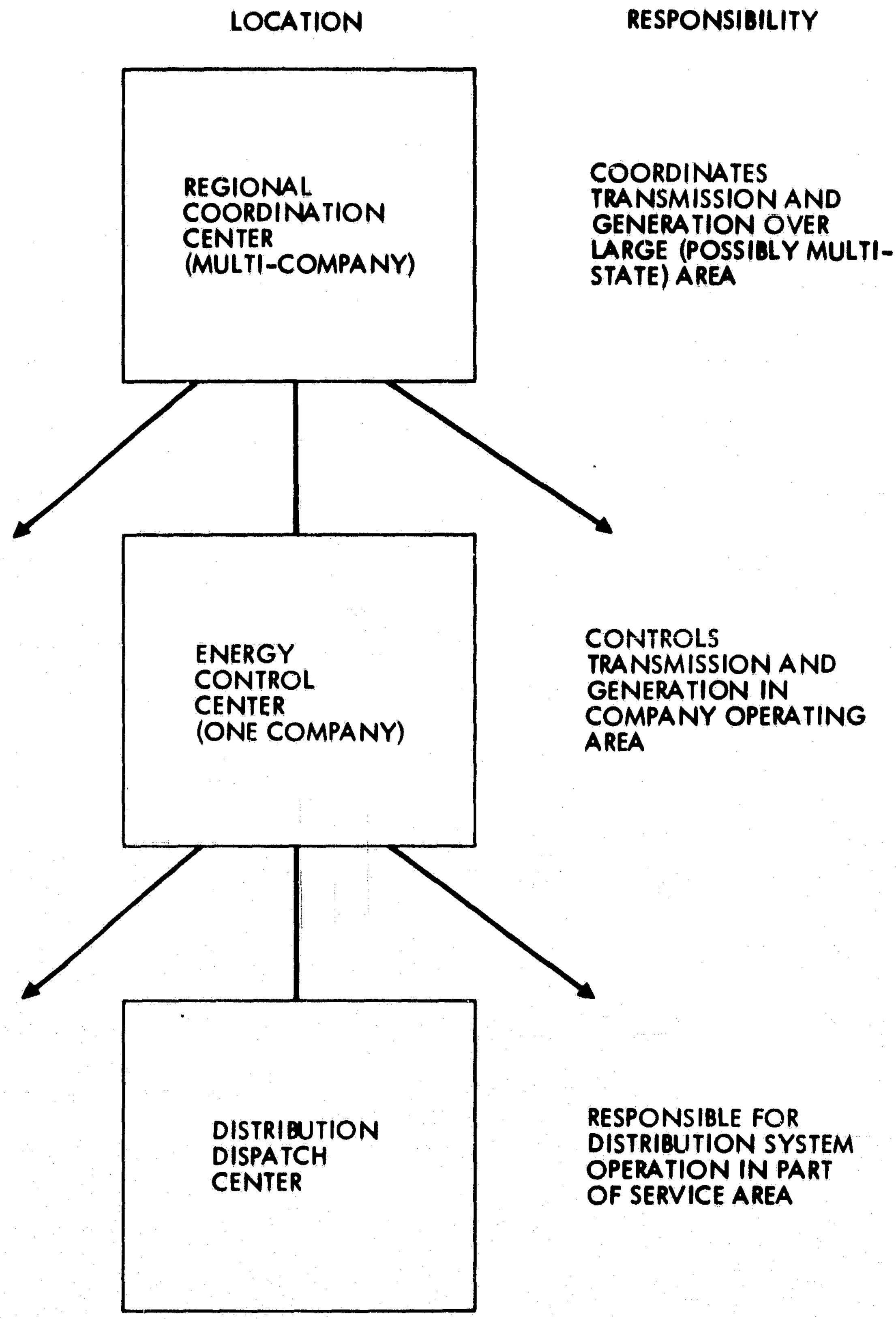


Figure 1-1. Power System Control Hierarchy (Typical).

be exercised from the same physical location at the generating station. In a more modern plant, control of all the parameters of the generator might be exercised remotely from the energy control center.

There has been little industry-wide standardization in the electric supply industry. The reason for this is obvious: independent development of electric distribution, transmission and generation systems has occurred over a very long period of time, and the lifetime of equipment is rather long. The result of all this is that, at the present time, equipment will have been installed as long as 20 or 30 years ago, or at any time since then.

The activities of an energy management system include the management of all power and energy generation equipment within its area of control, the control of power flow to other areas, the diagnosis and correction of system electrical problems, and the recording of data pertinent to system operation, diagnostics and cost billing.

The primary objective of the energy control center (ECC) is to ensure a reliable supply of electrical power to its customers at a minimum system operating cost. Two other important objectives are to maintain the power network operating frequency and voltages at their proper values. Additionally, it is desirable to operate a power system in such a manner that the loss of generating units or transmission lines causes a minimum of disruption to the system. Control of power flow to meet contractual agreements with other power networks is a requirement. Lastly, the recording of data to confirm normal system operation, provide diagnostics in the event of system problems, and substantiate power and energy flows to other networks is needed. These factors are discussed in the following paragraphs.

Several precautionary steps are taken to minimize the chances of loss of power to customers. Multiple generators are frequently used at bulk power plants with the result that the loss of a single unit does not disable the plant. Power line networks interconnect bulk power plants in a system so that loss of a portion of one plant can be accommodated by transferring power from another bulk plant. Similarly, power transfer from one system to another provides security against loss of a major block of power from a bulk plant. Typically, systems are operated with sufficient reserve to be able to handle the loss of any generator or line in the system. Quick-response regulating units, or, sometimes, generation normally used for peaking, may be brought into service as an emergency power supplement. The scheduling of generator and transmission line maintenance for off-peak load periods helps to maximize the available reserve for emergencies.

One of the most effective ways of minimizing the operating costs of a power system is to emphasize the use of the cheapest energy source available, typically hydroelectric power. If sufficient inexpensive power does not exist within a system, it may be purchased from other systems. Another method of

minimizing costs is to maximize the use of the most efficient machines, taking into consideration the transmission losses involved in delivering the power to the loads. This process is known as economic dispatch.

Power system frequency is controlled by comparing system frequency to a frequency standard and using the frequency error to adjust the power settings of the system prime movers. System voltages are maintained within proper limits by adjusting generator excitation, adding reactive loads to the transmission system, or transformer tap-changing.

The maintenance of system security (invulnerability to equipment outages and line faults) is generally accomplished by performing a series of contingency analyses for specific network configurations. These analyses may be tailored to predicted system loading conditions and can be performed hours or days in advance. Contingency analyses may also use actual system conditions, and be performed almost in real time. Generation schedules or loadings may then be controlled so that system operation lies safely within the contingency conditions.

In order to inform the system operators of system conditions, and to present the results of the various computations performed at the ECC, the ECC is usually equipped with multiple cathode ray tube (CRT) displays, data logger and status indicators. As indicated previously, data may be used for power billing, diagnostic purposes, and as a data base for further power systems analyses.

In the next subsection, the functions and computations performed at an energy control center will be examined.

B. FUNCTIONS IMPLEMENTED AT THE ENERGY CONTROL CENTER

A number of functions are implemented at the ECC to accomplish the objectives discussed previously. Among these are automatic generation control (AGC), economic dispatch calculation (EDC), voltage/VAr control (VVC), static state estimation (SE), on-line load flow (OLF), and security monitoring (SM). These functions are discussed briefly on the following pages.

1. Automatic Generation Control

AGC is the regulation of the power output of electric generators within a prescribed geographical area to maintain the scheduled system frequency and/or the established interchange with other areas within predetermined limits. This is normally accomplished by adjusting the frequency set point for each generator governor from a central controller. Computation of the set point changes takes into account the inherent speed/load droop characteristics of

each governor and the desired apportionment of load among the various generators. Response times of the AGC control loops are typically on the order of a few seconds.

Information required to perform the AGC function includes the scheduled and actual power flow from the control area, the proportion of system power desired for each generating unit, the regulation characteristics of each governor, and possibly the power rate limits of each generating unit. The actual power flow from the control area and the generator outputs comprise the real-time information needed; the remaining data may be stored in a computer file and updated as required. System controller outputs to the generating units take the form of either power up/down commands or desired power levels, depending upon the requirements of the generator controls. The application of AGC to a control center requires an interface with the data handling system to receive generator and load flow data, to transmit commands to the generators, and to communicate with the system display.

2. Economic Dispatch Control

EDC is the distribution of generation requirements among alternative sources for optimum system economy. Consideration is given to the incremental costs of both power generation and transmission losses; generator outputs are then adjusted to minimize total system operating costs. Typically, a computer is used to estimate the proper generator outputs for optimum system economy; displays inform the operators so that they may make the appropriate adjustments. EDC computations are typically made at intervals ranging from 5 minutes to 15 minutes.

Data required to implement the EDC system includes incremental generating costs for each unit, and a set of penalty factors for transmission line losses. The latter are generally calculated off-line and only one set of constants is stored in the control center. Outputs of the computation are routed to the operator's display for their information. In this type of operation, the operators must consider the constraints imposed by generating unit capacity limits before acting upon the EDC outputs. A more sophisticated computational system is required to minimize operating costs under these and other system-imposed constraints.

3. Voltage/VAr Control

VVC is the process of maintaining line voltage and VAr flows within predetermined limits. Several power system control elements are available to provide line voltage control: generator excitation control, capacitive and inductive reactors, static VAr supplies, and tap-changing transformers. The first of these may be controlled as a part of the bulk power system; the last three are generally available through substation supervisory control systems.

4. On-Line Load Flow

OLF is the rapid calculation of power flow based on a specified vector of bus injection. In general, the bus injections are calculated from data obtained on-line and some off-line historical information. The bus injections may be obtained from the results of a state estimation routine. The output of the load flow computation may be transmitted to a CRT display for operator assessment of the network condition, or it may be used as an input to a contingency analysis program. Load flow calculations have historically been rather slow, but better computers and more efficient algorithms permit this calculation to be made almost in real time.

5. Static State Estimation

SE is a statistical procedure for making a best estimate of power system bus voltage vector magnitudes and phase angles (and hence, power flows, etc.) from a set of system measurements (usually of real and reactive power flows and voltage magnitudes). A dynamic version of the technique has been extensively used in the control systems of spacecraft; application to power systems is rather recent and covers only the steady-state condition. The technique calculates values for non-measured quantities and uses redundancy of measurements to permit statistical correlation and correction of the measurements, as well as the detection and correction of bad data. The output of the state estimator may be used as an input for on-line load flow calculations. Outputs may also be placed on one or more CRTs on the control center console.

6. Security Monitoring

SM is the on-line identification and dynamic display of the actual operating condition of the power system. Many measurements are involved in this function, including real and reactive power flows, bus voltages, circuit breaker status, transformer tap positions and line currents. This information is used for a display of the system configuration. The SM function is likely to include a set of limit tests for system operating parameters for an indication of out-of-tolerance conditions or proximity to limit conditions. Several limit levels may be employed, such as normal, alert or critical. If sufficient data are available, security monitoring may also be able to evaluate data validity by cross-checking multiple measurements. The primary output form for this function is one or more CRT displays indicating the condition of the system. Data for the security monitoring function are generally taken at a rate sufficient to permit updating the displays every few seconds.

The foregoing description of the functions of an energy control center is not meant to be all-inclusive. Rather, the intention is to provide a background of concepts for the later discussion of the impacts of Dispersed Storage Generation (DSG). It is recognized that other EMS functions are being developed or have been proposed. For example, an optimum power flow program would include scheduling according to NO_x emission limits (as occurs in

California, for example) in its computations of the dispatch problem. However, to consider all the functions which might be implemented in a control center would detract from the theme of this report.

C. ENERGY CONTROL CENTERS

Energy control centers, like most power system hardware, have evolved in size and complexity. Early systems were based on mimic displays of the system along with analog meters for readouts of system parameters. Some data loggers were used. Control was manual, and some operator skill was required.

As power systems become more complicated, the need for automation is obvious. Computers are needed to reduce data volume for presentation to the operator (either by CRT or by a computer-controlled wall mimic), and usually to perform the control functions discussed in the previous subsection. Because the computer is so intimately involved in the control of the system, dual-computer configurations are frequently used to improve reliability.

Data are acquired through supervisory control and data acquisition (SCADA). The SCADA system has remote terminals at all the important generating stations and transformer stations on the system. These data may be updated every second, and are usually checked for obvious errors before being passed on to the main computer.

The prevalence of control functions carried out at the various control centers also varies considerably. By far the most prevalent functions are automatic generation control, economic dispatch and security monitoring. The remaining functions are far less common, as indicated in the bar chart of Figure 1-2. It is anticipated that the less common functions will increase in usage as computational equipment and software become more sophisticated.

Brief descriptions of energy control centers around the world are presented in Appendix A.

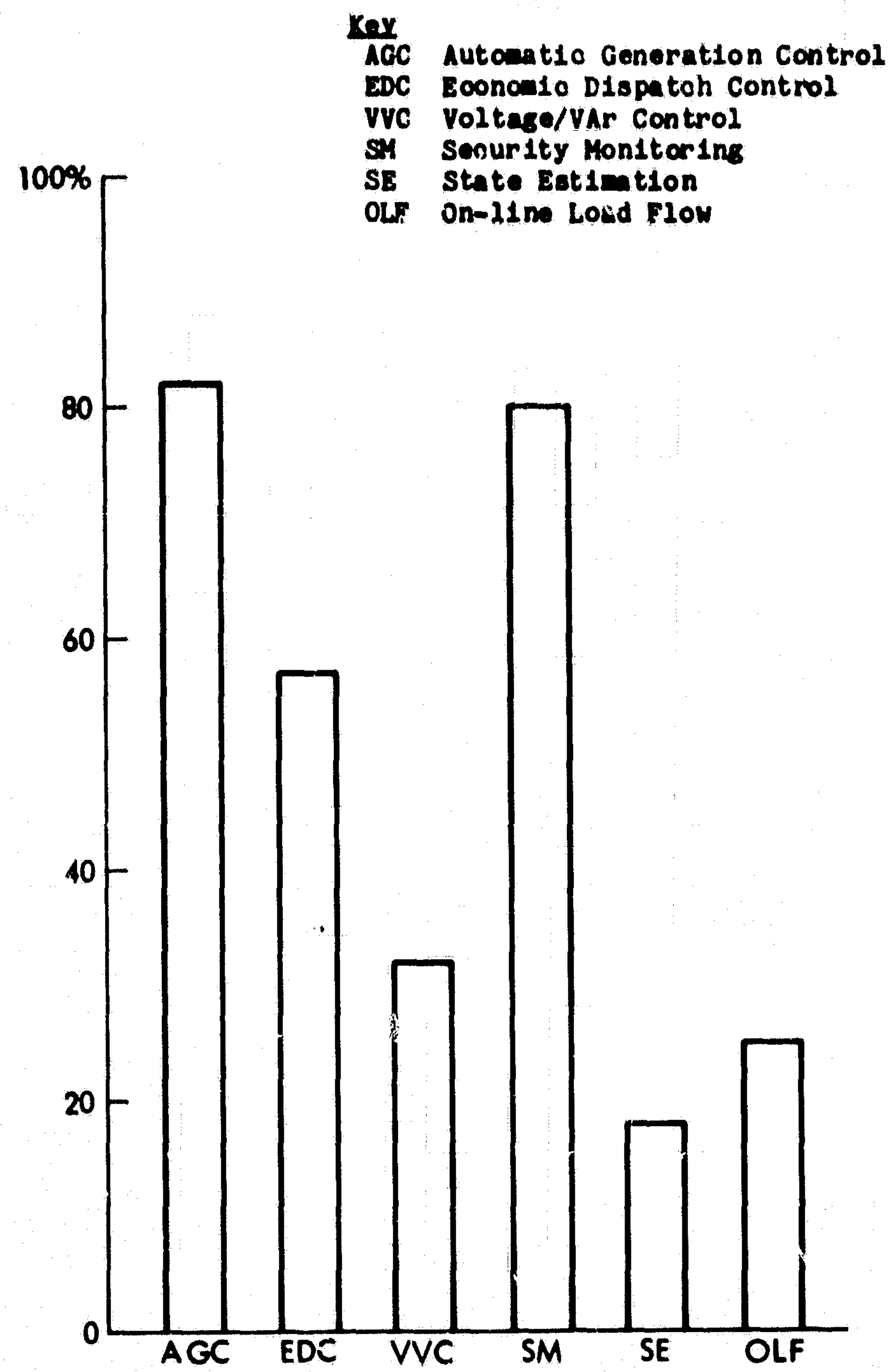


Figure 1-2. Prevalence of EMS Functions in System Control Center

SECTION II
DISPERSED STORAGE AND GENERATION

A. DEFINITION OF DSG

Over the last decade or so there has been an increase in the activity devoted to the development of renewable resources for the generation of electric energy. Many of these generators are small and can only be economically connected to the distribution system or to the subtransmission system.

In general, DSG may be defined as any source of electrical energy (including storage elements which act as sources at times) connected directly to a utility distribution system.

An essential part of this definition is the connection to the distribution part of the electricity supply system. Because the power ratings of distribution system hardware are smaller than the ratings of transmission equipment, it follows that the power rating of DSG is also smaller. However, a DSG connected to the subtransmission system of a large utility may be larger than a central station generator at a small utility.

Electric generators are customarily interconnected by a transmission system which allows for the most economical use of available generation resources as the load and the availability of generators change. Often, the transmission system is designed to carry large blocks of power from an area with generation capacity to an area of load.

This situation contrasts with the anticipated use of DSG. Connected to the distribution system, which is generally a radial system, DSG is not likely to be used to supply remote loads. A high penetration of DSG could, of course, change transmission line loading. However, it is unlikely for radial distribution to function as a power collection network to feed power to a transmission system.

Neither size nor impact on the utility system may be used alone as a criterion to identify DSG. Rather, DSG may have some (generally more than one) of the following elements:

(1) Small size (less than 30MW).
(2) Contains storage.
(3) Intermittent source (such as sunlight or wind).
(4) Connected to subtransmission or distribution systems.
(5) Fuel or energy source dispersed or uniquely available at site.

B. EXAMPLES OF DSG

The examples of DSG given below are followed by estimates of the potential to assist meeting the electrical energy needs of the nation.

1. Biomass

Biomass is a word describing plant material. The use of growing plants as a fuel is not new. The overharvesting of the English countryside for its wood is considered, by some historians, to have been responsible for the Industrial Revolution. In that instance, the resource renewed itself more slowly than it was being consumed, and coal, an alternative, came into popularity. Coal, oil, and gas, the fossil fuels, do not renew themselves at all, and there is a certain irony to the attention again being given to the use of renewable fuels.

If the ultimate use of the biomass is combustion, the overall efficiency from solar energy to electric energy is very low. Figures of less than 1% are quoted in one recent study (Reference 2). However, it is thought by some that the total quantity of raw material available is so large, if one includes animal waste as well as agricultural waste and silviculture (forestry), that the low efficiency is not important.

Methods other than simple combustion are also possible. For example, anaerobic digestion of wastes to yield combustion products such as methane is an alternative cycle.

2. Geothermal Energy Conversion

The thermal energy of the earth's interior is sometimes evident at or near the surface. The Romans knew this when they built the famous spa at a town now called Bath, in England. Geothermal energy was (and still is) used to heat the water flowing into a number of large baths. There are some areas in the United States (principally on the west coast) where vapor or water-dominated geothermal resources are available. There are many areas of the United States where temperatures of potential interest exist, but these are "dry, hot rock" type geothermal resources. Programs have been directed at the generation of electric energy through introduction of water, circulated through drilled conduits.

For electricity generation, vapor, or water-dominated reservoirs can be used, or water may be introduced and circulated through the dry hot rock. Vapor-dominated reservoirs (steam) are preferred, since they can drive standard turbines with minor modification. Geothermal energy is usually of relatively low enthalpy, and it is uneconomical to transport the hot fluid for any appreciable distance. This means that the generators must be located where the

geothermal source is, and the energy removed electrically. If the source is small, geothermal can qualify as DSG.

3. Hydroelectric Pumped Storage

A bidirectional hydro plant pumps water from a lower reservoir to a higher one during periods when the utility is under light load. During heavier load periods, the hydro plant generates power from the flow of water down to the lower reservoir. These flows may be combined with a net average flow for irrigation or municipal water supply. Economies of scale have favored large installations, but smaller ones of only a few megawatts are under active consideration.

4. Solar Thermal Electric

These systems collect solar radiation, heating a working fluid to high temperatures to operate a mechanical-electrical generating system. Thermal energy storage may be included in the approach, and excess heat from the system can be used for other purposes, such as space heating. A wide range of power levels, system designs and equipment types can use this approach; however, the method is not at present fully commercialized.

5. Compressed Air Storage

This method of energy storage uses off-peak electricity to pump air into underground storage caverns. The air thus compressed is subsequently used to feed a combustion turbine, so that the apparent efficiency is improved. Since the compressor normally uses about 2/3 of the power output of the turbine, the rating of the system can be increased by a factor of three. In the generating mode, the entire turbine power which results from the burning of fuel oil or gas is available to produce electricity.

Whether compressed air storage (CAS) qualifies as DSG is really determined by the minimum economic size of the storage caverns. For example, the CAS system in Germany (Huntorf) is rated at 170 MW , which is a little large for a DSG.

6. Photovoltaics

Photovoltaic cells convert sun light directly into electrical energy by the stimulation of the junctions of dissimilar materials by solar photons. Low solar intensity at the earth's surface (approximately 1 kW/m^2) and maximum

achievable cell efficiencies in the order of 20% combine to require extensive land areas to produce significant amounts of power. Insolation cycles and variable weather conditions further limit the amount and availability of photovoltaic power, while conversion equipment is required to transfer the DC output of the solar array to an AC power system. Consequently, a significant problem faced by users of photovoltaic systems is the high initial capital cost. As considerable resources are presently being devoted to the reduction of these costs, competitive photovoltaic equipment should become available by the mid 1980's.

7. Wind

Wind generation systems employ a propeller or a wind turbine to drive an alternator either directly or through a gearbox. For utilities, these systems may consist of one or more moderate size units (200 kW to 3 MW). Control systems for wind generators must decouple the generator in very light winds to avoid having the propeller driven by motor action. In very heavy winds, the system must again be shut down to avoid damage. Because of this, and because wind is not generally a steady resource, wind systems presently are only economical in limited applications. However, like photovoltaics, this is a dynamic situation.

8. Fuel Cell

A fuel cell permits the direct conversion of chemical energy to electrical energy. A fuel cell consists of the electrodes separated by an electrolyte. A reactant gas, such as hydrogen in the case of the phosphoric acid fuel cell, is passed over one electrode and air is passed over the other. Electrode temperatures of 200-300°C are not uncommon. The hydrogen can be derived from a number of sources/methods. It is commonly derived from the reforming of mixtures of methanol/water or hydrocarbons/water. In that case, the principal wastes are carbon dioxide and water.

The fuel cell is a developing technology, and it is uncertain at this point what range of sizes can be produced to furnish electrical energy economically. Some fuel cells qualify as DSG.

9. Storage Battery

Storage batteries are not truly sources of electrical power. In fact, their normal inefficiency involves a net power loss. However, the availability of power which can be very rapidly controlled in combination with a non-controllable power source such as wind or solar can provide a steadier output to the power system. Batteries employ electrochemically dissimilar electrodes in conjunction with an electrolyte to provide a means of converting electrical

energy to chemical form. This stored chemical energy may be subsequently released as electrical energy through a suitable external circuit. For utility systems, an inverter is required to change the stored dc energy into ac power, while transformation and rectification are required to charge the battery from ac lines.

Storage improves the utility load factor and reduces the net cost of energy by improving the utilization of existing equipment.

10. Hydroelectric (low head)

Hydroelectric plants convert the energy of naturally flowing water to electrical energy by using water turbines to drive electrical generators. Small units located on minor rivers or streams may use this source of energy to supply local needs through connection to distribution feeders.

The economies of scale are such that relatively small hydro-generators are economical (Reference 3). The technology is already developed.

11. Cogeneration

Cogeneration is the combined production of process heat and electricity. Industries and utilities needing both of these forms of energy can generally achieve a net reward in cost benefit by using a facility that fully utilizes the heat of combustion. For example, some exhaust steam from a steam turbine may be sent to nearby commercial or industrial facilities while the remaining heat and steam is used for local space heating or manufacturing processes. Since many co-generation facilities use oil-fired turbines, they do not necessarily contribute to a national goal of reduced oil imports. However, co-generation does employ a fully developed technology and is of immediate economic benefit. It must be considered in any discussion of DSG.

C. THE CONTRIBUTION OF DSG TO SUPPLYING ENERGY NEEDS.

The future growth rate of electrical demand in the U.S. is expected to be smaller than the historical figure of 6 or 7% per annum. Nevertheless, installed capacity is expected to be about 1200 GW by the year 2000 (Reference 4).

The contribution that DSG will make to this figure has been variously estimated. A range of 4 to 10% is considered by some to represent optimistic assumptions. If 5% of installed capacity is DSG in 2000 and represents 60 GW, the mature technologies, such as hydro and cogeneration, will make the largest

contribution; perhaps half of the 5% figure assumed for DSG. The other technologies; wind, solar thermal electric, pumped storage, hydro, and photovoltaics might divide the remainder about equally. However, it is likely that their share will be increasing and the share of hydro and cogeneration will be decreasing as the supply of available sites is exhausted.

These estimates are not meant to be convincing in terms of the actual contribution of any particular source. For example, estimates for hydro range from 9 GW to about 60 GW, and for cogeneration the range seems to be from 60 to 190 GW (Reference 5). Therefore, to arrive at an accurate figure for the total contribution is clearly very difficult. Nevertheless, when the contributions of the various technologies are considered individually, the assumed figure of 5% by the year 2000 would seem to be reasonable. (Local considerations, such as utility size and renewable resource availability, may increase the DSG contribution to as much as 20%). With a suitable economic and regulatory climate, DSGs can make a worthwhile contribution to the nation's energy needs.

D. IMPACT OF DISPERSED STORAGE AND GENERATION

In order to understand more clearly the impact of DSG, it is best to separate the attributes of DSG into two major groups. First, those which will influence the real-time control of the power system and second, the attributes which will influence only the longer term operation of the system. The first group of factors clearly will interact with system related factors, whereas the latter group will interact with institutional, political or environmental attributes of the power system.

1. DSG Attributes which Influence Real-Time Control

An obvious factor influencing control is size or power capability. To a large extent, this determines the level in the distribution system at which the DSG is connected. Size will also affect the amount of control required by the utility since the potential for system disturbance is greater for a larger unit.

Power source availability (hydro supply, consistency of sunlight or wind, etc.) strongly affects the way in which a DSG unit would be used, and also determines whether or not the DSG can be reliably scheduled.

Power source stability, in terms of short-term variability, is a significant factor. For example, rapid fluctuations in power flow because of wind gusts or broken cloudiness could require additional line voltage regulation.

The capability for DSG voltage control can assist in local line voltage control. In some instances, reactive power flow control can be provided as well, such as when a dc inverter is connected to a system with independent voltage regulation. The dc system can vary the apparent power factor of the source.

The time-response characteristics of the DSG are important. A unit which responds rapidly to control signals may be used to help stabilize a situation in which other DSG sources or loads are varying rapidly.

Harmonic generation from a DSG unit is a source of possible interference with other equipment on the same portion of the distribution network or with line carrier control signals. Internal or external filtering of the DSG unit may be required to provide adequate harmonic suppression. This is normally considered to be a design question, although it is not a simple matter to specify just how much harmonic filtering is required to make a DSG acceptable for connection to a utility,

Automatic start capability on a DSG unit greatly enhances its usability, since it can be easily controlled from an energy control center without requiring the intervention of an operator. Automatic start in this context includes start-up and acceleration if applicable, synchronization and connection to the system.

Some DSGs have special requirements such as azimuth control on wind units and solar tracking for some photovoltaic arrays or solar thermal units. These requirements must be considered in a monitoring sense for some DSG units.

The possible comparisons of DSGs with respect to the factors so far discussed are shown in Table 2-1.

Table 2-1. Comparison of DSGs

DSGs	Size	Power Source Availability	Power Source Stability	Energy Limitation	DSG Voltage Control	Response Speed	Harmonic Generation	Automatic Start	Special DSG Factors
Biomass	V	G	G	N	Y	F	N	Y	Y
Geothermal	M	G	G	N	Y	M	N	Y	N
Pumped Hydro	L	G	G	Y	Y	F	N	Y	N
Compressed Air Storage	L	G	G	Y	Y	F	N	Y	N
Solar Thermal	V	?	P	N	?	V	?	?	Y
Photovoltaics	V	?	P	N	?	F	Y	Y	Y
Wind	S	?	P	N	?	F	?	Y	Y
Fuel Cell	V	G	G	N	Y	F	Y	Y	N
Storage Battery	V	G	G	Y	Y	F	Y	Y	N
Low-head Hydro	S	V	G	N	Y	F	N	Y	N
Cogeneration	S	G	G	N	Y	F	N	?	N

KEY: L-large, M-medium; V-variable, S-small; Y-yes, N-no; F-fast, P-poor; G-good, ?-uncertain

Some of the entries in Table 2-1 are approximate (for example, it is not always true that low-head hydro is without energy limitations), but some interesting features emerge.

The most obvious feature is the diversity among the DSGs. Only two have identical entries in all columns (pumped hydro and compressed air storage) and it could be that neither of these is truly a DSG. This lack of consistency makes difficult the task of assessing the impact of DSG on the power system.

A second feature which emerges from this table is that generally the renewable-resource generators score poorly in the power source stability column, with the possible exception of low-head hydro. This topic will be resumed in Section IV.

Each of the factors described above as attributes of DSGs may interact with one or more of the functions of the energy management system or energy control

center. A matrix of these interactions is shown in Table 2-2. The matrix was constructed subjectively. A particular DSG attribute was considered for possible interaction with each of the energy management functions in turn. Once this is done, the EMS functions can be compared to see which are most impacted by the integration of DSG. A discussion of the more important interactions follows in Section 3.

Table 2-2. Interaction Between DSG Factors and EMS Functions

Functions \ Factors	Size	Power Source Availability	Power Source Stability	Energy Limitation	DSG Voltage Control	Response Speed	Harmonic Generation	Automatic Start	Special DSG Factors
Automatic Generation Control	1	1	1	1	0	1	0	1	0
Economic Dispatch	1	1	1	1	?	0	0	1	0
Voltage Control	1	0	1	0	1	1	?	0	0
Protection	1	0	1	0	1	1	1	1	1
State Estimation	1	0	0	0	0	0	0	?	0
On-Line Load Flow	1	0	0	0	0	0	0	0	0
Security Monitoring	1	0	0	0	0	0	0	0	0

KEY 1 interaction probable 0 interaction unlikely
? interaction possible

SECTION III
CHANGES AT THE ENERGY CONTROL CENTER

A. INTRODUCTION

The impact of DSG (as indicated by the number of ones in Table 2-2) is limited to the real-time control functions. That is to say, there are a lot of ones associated with automatic generation control, economic dispatch and voltage control, and few ones associated with the remaining functions, state estimation, load flow and security monitoring. Protection, of course, is significantly impacted; this subject will be discussed in Section IV. Before turning to a discussion of the EMS functions that seem to be impacted by DSG, it may be worthwhile to examine briefly the reasons why the remaining functions are not influenced by the integration of DSG.

Load flows, contingency analyses and state estimation have ordinarily been concerned with the condition of the bulk supply system. Assuming that the DSG units integrated into the distribution system are suitably sized (i.e. small), there would be little benefit in carrying out a load flow to a lower part of the power system. The load flow results for the bulk system will be unaffected by the details of the DSGs in the distribution system. This is not to say, of course, that the load flow in any given transmission line would not be influenced in the case of a significant penetration of DSGs. However, the effect on the bulk system can presumably be modelled by modifying its bus injections; detailed descriptions of the DSGs are not required.

A similar situation holds for state estimation and security monitoring. The system of concern has, until now, ended at bulk supply points or large distribution stations. Knowledge of the system below this level has not been required; it seems that this situation will continue to hold when DSGs are installed.

The distinction between these functions and those which are impacted by DSG seems to be that the functions influenced by DSG are related to generation control, and would continue to be so even if the generator is no longer in the bulk system. It is impractical to monitor every 20 kW DSG in quite the same detail as, a 1000 MW coal-station, but the ability to control it should certainly not be overlooked. Because of this, a dispersed control system, which could control small DSGs without presenting a burdensome problem to the ECC, is described in the next section.

A more detailed examination of the functions which seem to be significantly impacted by the addition of DSG is presented in the next section, beginning with three related functions: automatic generation control, economic dispatch, and voltage control.

B. GENERATION CONTROL

Automatic generation control normally works on the assumptions that regulating units are available, that an area control error can be defined and used as a penalty function in an optimizing algorithm, and that the state of the system external to the power system in question is not observable. Under these assumptions an area control error is normally defined as a function of two parameters. One parameter is the difference between the actual power being interchanged between areas and the power called for in the interchange schedule of the area, and the other is the frequency error. The frequency error may include a deliberate offset from the actual instantaneous frequency error in order to compensate for previously accumulated errors in system time.

If everything else remains constant and the prime-mover power to a generator inside the control area is changed, both the frequency and the interchange power will be affected. A control system attempting to minimize an area control error which is a simple function of frequency error and interchange power can only be effective if the system external to the control area is behaving properly so that the frequency error vanishes at the same time as the interchange error.

Typically, the area control error (ACE) is represented by:

$$ACE = dP + B(df)$$

where dP is the net interchange power error, df is the frequency error and B is the frequency bias. The quantity B is actually a coefficient relating changes in net interchange power to frequency variations for the area in question.

The area control error may be used directly, with appropriate scaling, to drive servomotors controlling the power settings of prime movers such as steam or hydraulic turbines. With this approach, a loss of control signal results in no power change in the generating units, thus minimizing system perturbations caused by momentary signal loss. In many cases, the area control error signal is integrated and added to the direct control signal to the prime mover control servos; this provides additional reduction of the long-term control error without sacrificing the system transient response.

Some types of prime movers, particularly large steam turbines, have relatively low limits in the allowable rates of power change because of induced thermal stresses. Other machines, such as the hydraulic turbine, can safely accept relatively high rates of power changes. This consideration, in conjunction with the relative costs of producing power, leads to the concepts of loading order and participation factor.

Loading order is simply the most appropriate sequence in which prime movers are loaded as the load on the control area is increased. From an economic viewpoint, the most desirable sequence would be first to load the least expensive machines to operate and bring progressively more expensive machines on line only as needed to satisfy the demand. Unfortunately for most utilities, water power, which has the lowest operating cost, is generally insufficient to meet the demand. Nuclear power plants, which have a lower operating cost than oil-fired steam plants, have very restricted heating and cooling rates so that they are used to supply a steady component of demand. Alternative units must be used to supply the more rapid variations in demand. The loading order thus becomes a compromise between supplying power at minimum cost and maintaining adequate power flexibility to accommodate rapid load changes.

In practice, the nuclear and very large oil-fired steam plants are generally brought up to full, or most economical, load and held at this level. This is generally referred to as base loading. Other units with higher load rate capability are used to provide the variable portion of the demand. These are referred to as regulating units. Gas turbines may be used for this purpose even though their operating costs are higher than steam units: their very short starting times (on the order of a few minutes) and relatively quick response to load changes make them attractive for peaking and regulating use.

Alternatively, some portion of a system's hydraulic turbine power capability, if available, may be held in reserve to provide for system load variations. For example, an on-line turbine that is only partially loaded in order to maintain a capability for power regulation is said to provide a portion of a power system's spinning reserve. The spinning reserve needed for a utility may be a contractual requirement negotiated with other utilities as a part of participation in a large multi-utility network, or it may be the result of previous experience with the load on the system.

A utility may have a wide variety of types of generating units delivering power simultaneously to the system. To control the system so that each generating unit delivers the desired contribution to the load as it varies, a coefficient known as the participation factor is applied to the area control error before it is summed with the appropriate nominal load for the generating unit and sent to its control servo. For example, a nuclear-powered unit may be intended only for base load operation, in which case its participation factor would be zero.

C. GENERATION CONTROL AND LOADING ORDER: AN ALTERNATIVE

If a DSG is schedulable and controllable, its power output should be coordinated with the other generators in the system.

In this subsection, the problem of generator control is addressed from the point of view of the energy control center. Even in a large utility, the number of generators participating in the AGC is not likely to exceed 20-30 machines. It seems that the addition of DSGs in large numbers, hundreds or possibly thousands, merits a reexamination of the way in which units are operated under AGC control.

To change the power output of a generator, the prime-mover input power must be changed. For example, in a coal-fired unit, more coal must be ground, boiler conditions changed, and more steam admitted to the turbine. The relationship between input and output power is not a smooth function because of the changes in valve settings, and boiler and turbine efficiencies. An example is shown in Figure 3-1.

Because the conversion from coal to electrical energy is mechanical and lossy, some input is required even for no output. As the input is increased, most of the additional input goes to increasing the output, and the input/output curve of Figure 3-1 is not far from a straight line.

In the classical derivation of economic dispatch (Reference 6 and 7), the input/output curve is approximated by a curve, sometimes a straight line, but usually a parabola or a cubic.

If the input/output curve is expressed in terms of input cost versus output power, the slope of the curve can be used to find the most economical way of meeting the demand. The slope of the input cost curve is known as the incremental cost. The incremental cost generally increases as the output power increases as shown in Figure 3-2.

The minimum cost way of supplying demand[1] is to have all generators at the same[2] incremental cost. The point is easily demonstrated.

---

[1]Transmission line losses are neglected in this development.

[2]For large systems, the discussion applies to the regulating units. The larger, newer base-load units may have incremental costs which are always lower than the regulating units.

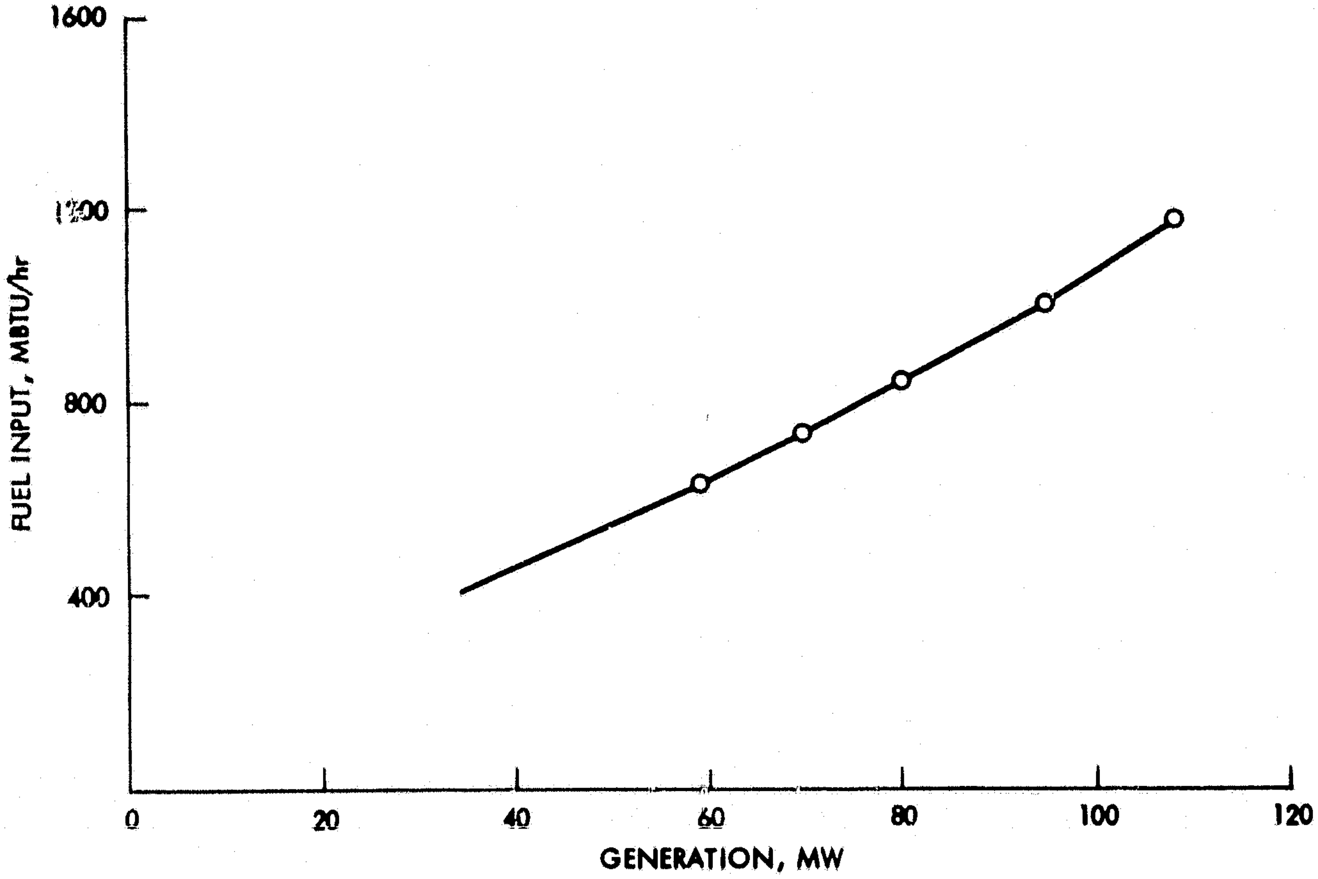


Figure 3-1. Generator Fuel Consumption

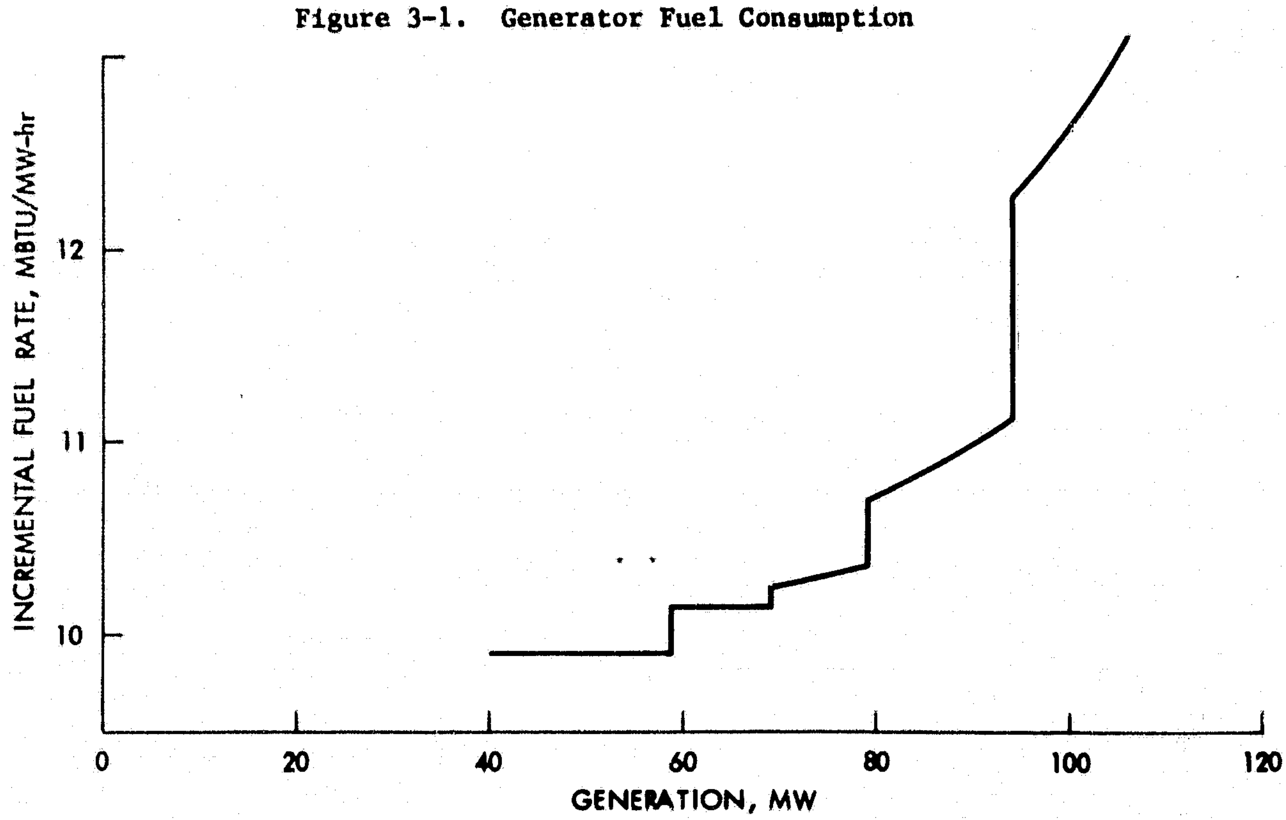


Figure 3-2. Generator Incremental Fuel Rate

Suppose two generators are supplying a load, and that they have unequal values of incremental cost. If a megawatt of power is taken off the unit with the higher incremental cost, and put into the other unit, obviously the cost of supplying the load is reduced. This process can be repeated until the incremental costs are equal. To continue to reduce power in the same unit will result in a reversal of roles: the unit which was at first operating with the lower incremental fuel cost will now have the higher one, and will be delivering power uneconomically. In the classical proof, this can be shown by the method of Lagrange.

It has been stated that the input/output curves were usually approximated by smooth curves. If the input/output curve is a parabola, the incremental fuel cost curve is a straight line, as shown in Figure 3-2.

Other approximations are possible. A piecewise linear approximation can be made to the input/output curve. If three segments are used, the incremental cost curve is a series of steps. This is shown in Figures 3-3 and 3-4.

It might be thought that Figure 3-4 is a poor approximation to the incremental cost curve of Figure 3-2. However, it should be remembered that Figure 3-2 is itself a curve based on an approximation, and it may not have any better claim to represent the true situation. The essential difference is that Figure 3-2 is based on a smooth curve approximation, whereas Figure 3-4 is based on a piecewise linear approximation, in this case of only three segments. It is not obvious which approximation results in the lower production cost.

The linear approximation method has two advantages over the classical method. First, load-following usually means action from only one generator at a time, meaning less wear and tear and therefore, lower maintenance costs. Second, the determination of loading order and the choice of regulating units is greatly simplified. This second point has implications for the distributed control methods considered in the next section. Since the incremental cost is constant over a range of power outputs, the choice of which unit to move at any time can be made using simple comparisons.

An example, taken from Kirchmayer is used to illustrate the foregoing discussion (Reference 6). The fuel consumption characteristics of two 100 MW represented by the following parabolic functions.

$$F1 = 80 + 8P1 + 0.024P1^2$$
$$F2 = 120 + 6P2 + 0.04P2^2$$

F1 and F2 indicate fuel consumption in millions of Btu (MBtu) per hour and P1 and P2 are power output in MW for units 1 and 2 respectively. These curves are

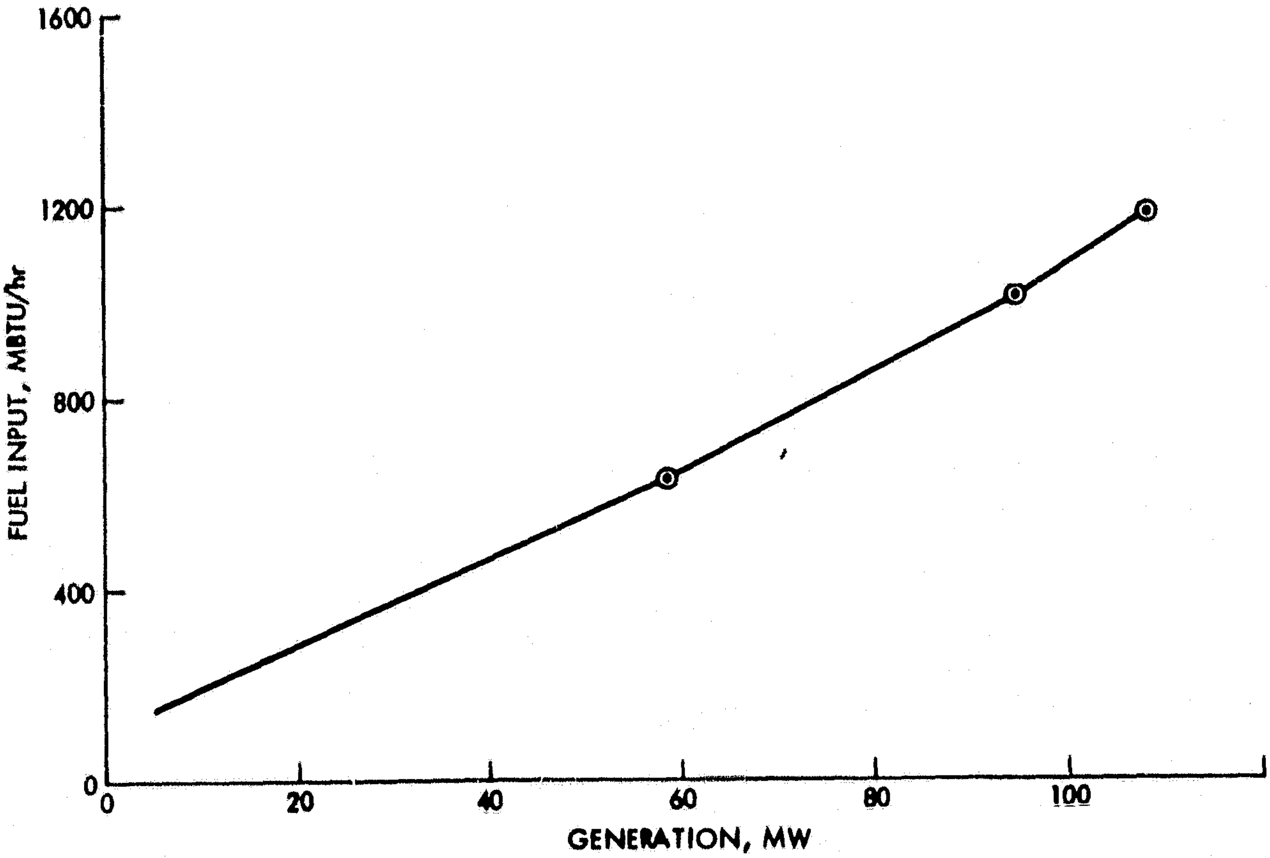


Figure 3-3. Fuel Consumption, Linear Approximation

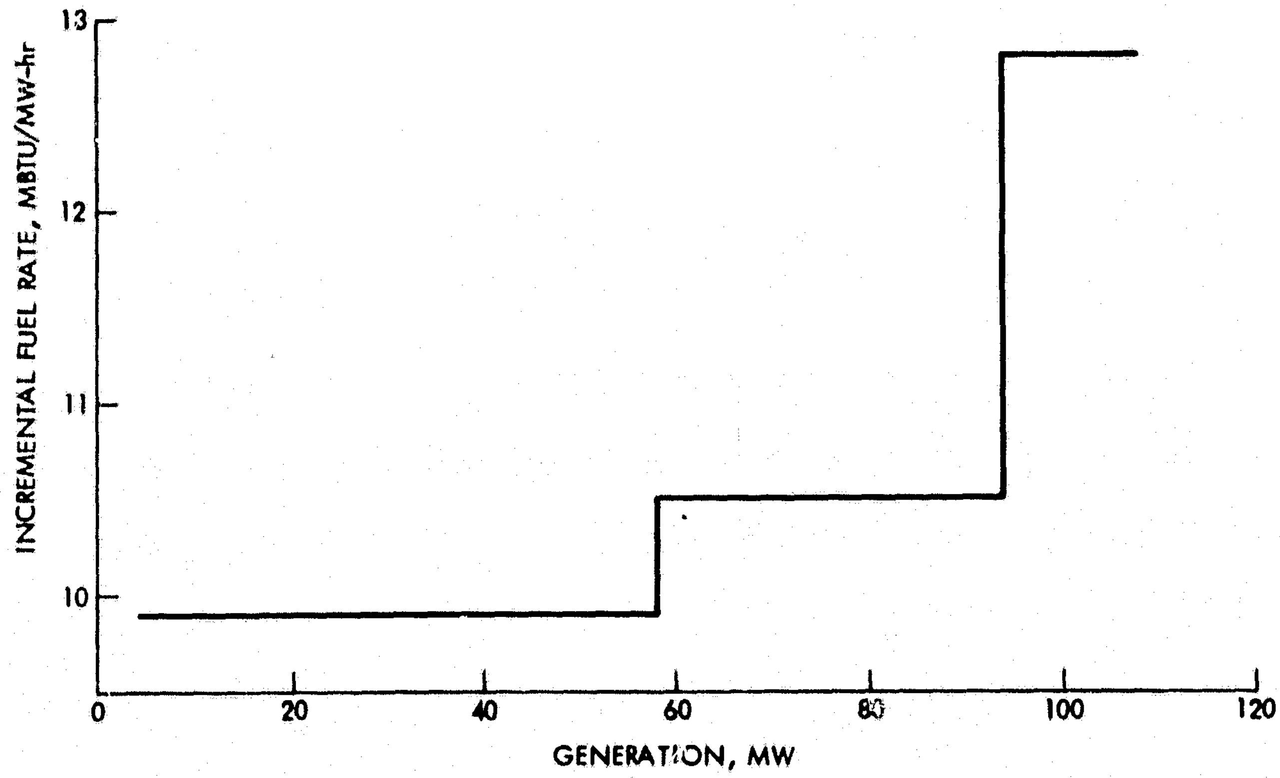


Figure 3-4. Incremental Fuel Rate, Linear Approximation

plotted in the lower portion of Figure 3-5. The corresponding incremental fuel rates are the straight lines in the upper part of the figure.

If both generating units are generating, the most economical mode of generation is with both units at the same incremental rate (subject to maximum and minimum power constraints). This condition is exhibited in Figure 3-6, in which the power contribution of each unit is plotted versus the total demand on the system. As indicated in the figure, in the region from about 40 to 185 MW both machines must be adjusted to compensate for load changes, and the adjustments are at different rates.

A pair of two-segment approximations to the fuel consumption equations are shown in the lower portion of Figure 3-7; the corresponding incremental rates are indicated in the upper portion of the figure. In this approximation, the rate curves are simple step functions. With this control scheme, only one generator at a time is altered in power setting, as shown in the generator contribution curves of Figure 3-8.

Suppose the system load increases from 20MW to 200MW over a period of time. According to the first (classical) approximation, unit 2 first picks up the additional load alone. It does this until it is generating a little over 30MW and the total load is a little over 40MW. At this point, unit 1 starts to pick up a fraction of the additional load, and actually picks up load faster than unit 2. By the time the total load is a little over 130MW, the generators are producing the same power. Unit 1 reaches its maximum power limit (100MW) first, at which point unit 2 is producing 85MW. From here on, unit 2 picks up all additional load.

If the units are operated according to the piecewise linear approximation, unit 2 again starts off by picking up all the added load. It continues to do this until its output is a little over 50MW, and the total demand is a little over 60MW. Beyond this point, all additional load is picked up by unit 1, and unit 2 is left alone. Unit 1 continues in this way until it reaches full output, at which time system demand is about 150MW. Unit 2 picks up all load beyond this point.

Although the two approximations result in incremental cost curves which appear to be quite different, the way in which the generators would be used to supply an increasing demand is not so different. In each case, unit 2 starts off first, and unit 1 reaches maximum power first. The biggest difference is that in the linear approximation method the load changes are satisfied by only one generator at any time.

This approximation method results in a loading order that can be determined by a simple sorting algorithm, and the choice of regulating unit at any time can be determined by an algorithm based on simple comparisons. Both of these

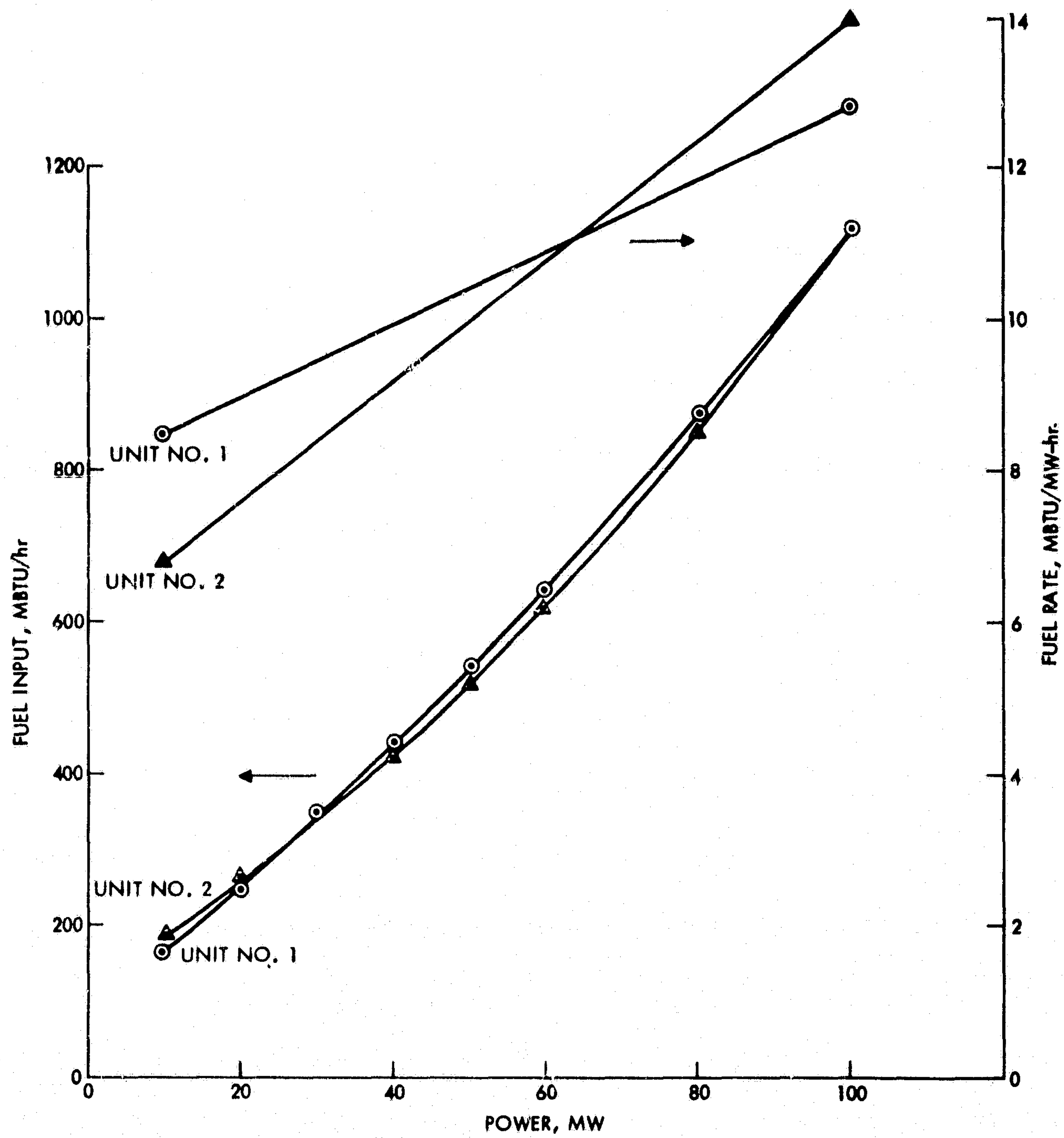


Figure 3-5. Fuel Consumption and Incremental Rates

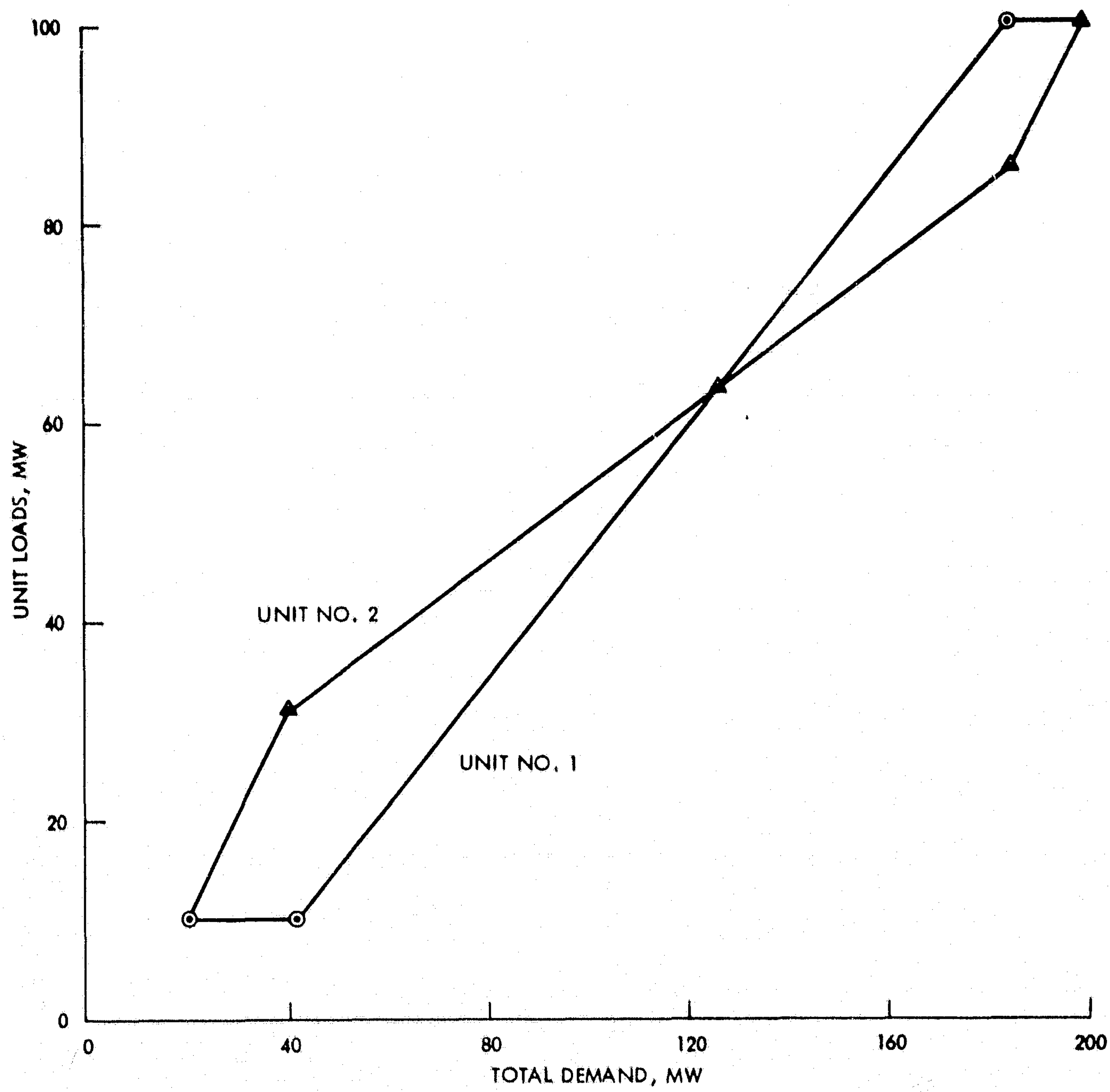


Figure 3-6. Generator Power Contributions
(Parabolic Approximation Case)

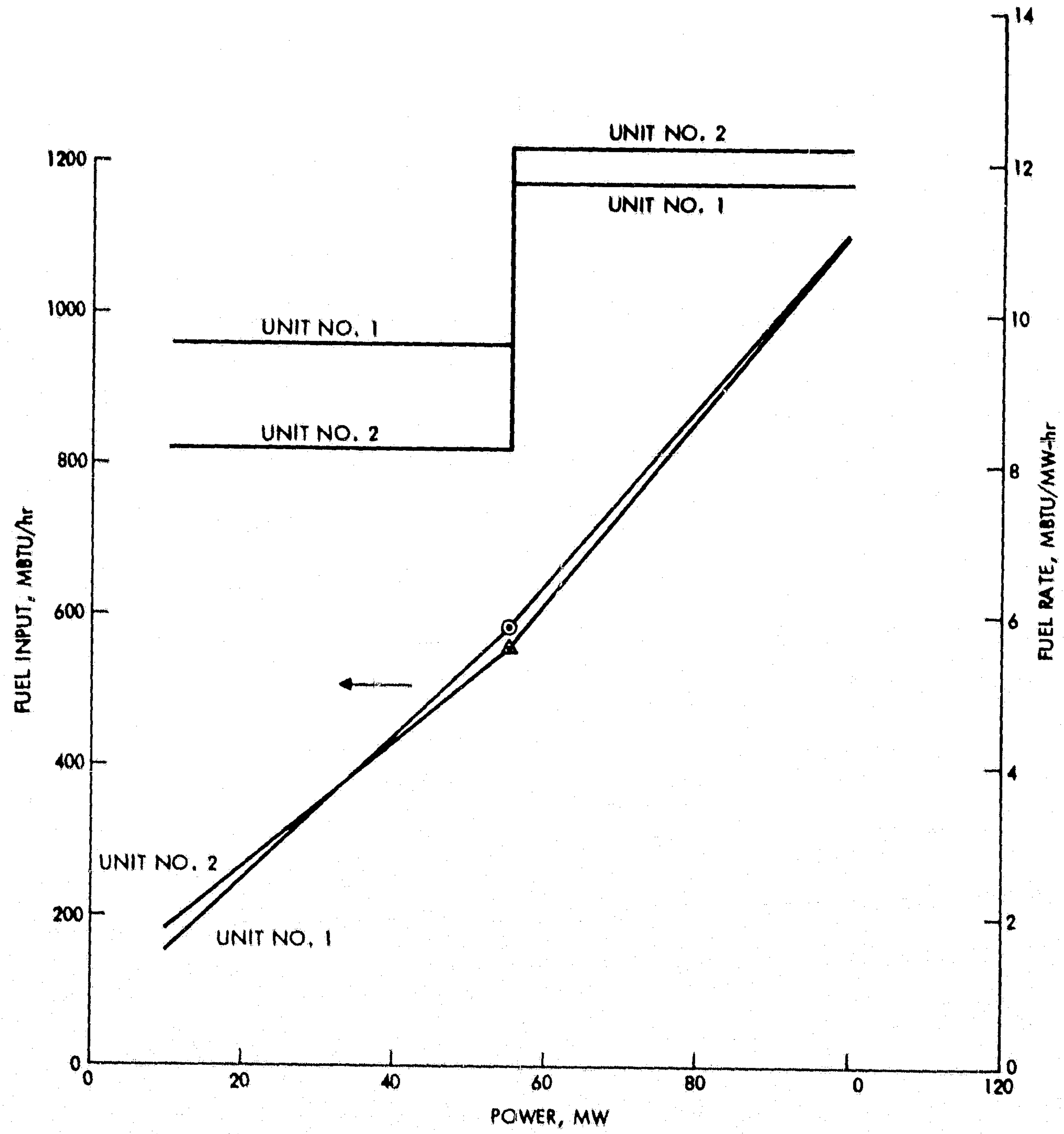


Figure 3-7. Two Segment Approximation to Fuel Consumption Curves

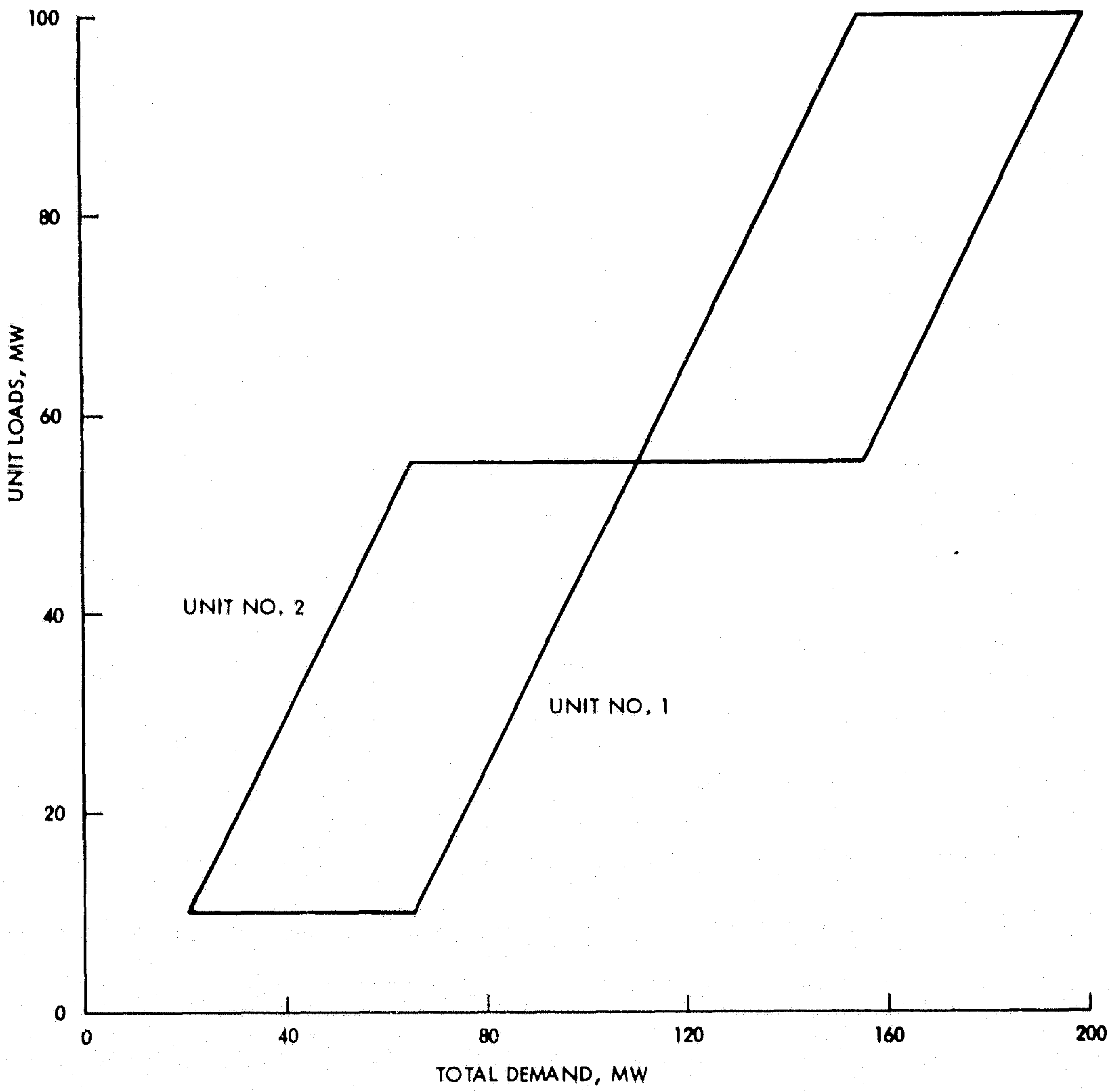


Figure 3-8. Generator Power Contributions
(Linear Approximation Case)

are the kind of algorithm that can make effective use of the compare and conditional jump instructions in the instruction sets of most computers. Small computers can execute such algorithms very efficiently and rapidly.

It seems that the piecewise linear approximation to the input/output curve has much to commend it as far as simple computation for DSG control is concerned. The method might be used for large generators too, and in this application could result in some changes in the way economic dispatch is applied. As Schweppe has pointed out (Appendix B) the quantity which should determine the output from any particular generator is the system incremental cost. If this information is available at each generator, it can determine its proper output. Decentralized economic operation is possible, and the question of participation factors does not arise.

D. THE IMPACT OF DSG ON GENERATION CONTROL

The automatic generation control process can be influenced in two ways by the addition of DSGs within the control area. First, if the DSGs are controllable and schedulable, there is the question of their placement in the loading order of generators. This loading order or generation schedule may conveniently be divided into three broad categories: base load, intermediate (including regulating units), and peaking. The position of a schedulable DSG in this arrangement is dependent upon considerations of economic dispatch, and will also depend on the resource of the DSG. A pumped-storage hydro might be used as a peaking unit, since it is a limited energy resource, whereas a landfill-gas unit might be base loaded, since the resource is continuously available. (On the other hand, the resource for the landfill-gas unit is also storable, so that such a generator might be scheduled for increased output at times of system peak).

The addition of a significant number of schedulable DSG's to a utility network may assist materially in providing improved power regulation capability. DSG's, being small, would be expected to have relatively rapid response. Some DSGs intrinsically have a capability to quickly change output (battery, for example). Thus, many DSGs could be used in a regulation mode, reducing the number of existing generation units used for regulation. Operation of the latter units in a base-loaded mode might be more economical.

Second, if the DSGs are neither controllable nor schedulable, there are two impacts on automatic generation control. The position in the loading order must be determined, but unlike the case of a schedulable DSG, the addition of considerable penetration of uncontrollable power sources could influence existing generation. For example, run of the river hydro, with no storage, would normally be base-loaded in the sense that all available power would be extracted. Similarly, photovoltaics would effectively be baseloaded although the available power would be at maximum during the day and zero at night. However, the photovoltaics resource, insolation, is rather less short-term predictable than hydro, and a cloudy day would have a significant impact on the

behavior of the regulating units on the system. Thus, regulating units would be required to follow the changes in DSG output as well as the changes in load, which would mean increased activity.

Non-schedulable DSG impacts on a utility network's regulating units could be reduced significantly if some form of energy storage, such as storage batteries, could be employed in conjunction with the DSGs. Solid-state regulators coupling the batteries to the system would be immune to the wear and tear of repeated cycling that mechanical control servos on conventional generating units would experience. The presence of the energy storage on the system should provide sufficient filtering such that only the slower trends in area control error would be observed by the automatic generation control system. However, this approach incurs additional energy losses.

Problems are sometimes experienced with existing AGC systems because, in an interconnected system, net interchange control cannot prevent individual line overloading. This arises simply because the power crossing a geographical area may not appear as a separate term in the area control error. This problem is usually said to be solvable only with higher level coordination which will weight the participation factors and frequency bias settings for the tie-lines, and which consequently requires knowledge outside the given geographical area. However, it may be possible, in some situations, to deviate from strictly economic dispatch to avoid transmission system overloads. This situation is somewhat analogous to optimal control in that it attempts to minimize a cost function while meeting system constraints. In this case, transmission line constraints are included as well as generator loading limits. The addition of DSGs to the system may result in increased flexibility because there will be the ability to control generation in locations where this ability does not presently exist. Although it would take a significant penetration of DSGs to influence transmission line loading, the contribution of DSGs should not be neglected in considerations of optimal control.

The automatic generation control described above is the executive part of the energy management function of economic dispatch. Economic dispatch is the function which minimizes the cost of meeting demand. This part of the computation will be considerably complicated by the addition of a significant amount of schedulable, controllable dispersed generation. The determination, for example, of the loading order becomes quite complicated with the addition of a large number of generators, and the fact that the power output prediction for some of the generators is based on a weather forecast. Some simplification of the problem may result from the use of the linear approximation method described earlier. It has yet to be determined how generators using intermittent resources should be assigned a capacity credit, and how their unpredictability should be included in the spinning reserve calculation.

One way in which it might be possible to reduce the unpredictability of the energy sources of some of the renewable-resource generators might be to include weather predictions in the computations made in the energy control center.

Some preliminary work has been done by Schweppe (See Appendix B) in the area of generation unpredictability due to weather variations. If the area of control is large, the weather within the area can be considered, to a first approximation, to be comprised of two kinds: micro-and macro-weather. Micro-weather is a term descriptive of weather affecting small geographic areas; macro-weather affects large areas. Macro-weather is predictable, or as predictable as any weather can be. For example, satellite data can give good predictions of approaching cloud cover that would affect photovoltaics or frontal storms that would affect wind generators. With the appropriate weather predictions, a good estimate of area-wide generation patterns can be made.

Micro-weather is not regarded as predictable, largely because data are not measured on a suitably small scale. Examples of microweather would include the effects of broken cloud or wind gusts. Since the micro-weather variations affect only small areas, the fact that they are not normally observed has no significance for the control area in general. The average of the micro-weather is the macro-weather, and this is predictable.

If suitable weather data are available, any important changes in generation due to weather variations can be predicted. The accuracy of such predictions increases as the lead time decreases.

In our earlier discussion of the functions of the ECC (Section 1), the frequency of calculation of the various functions was indicated. AGC is one of the fastest operating functions, with recomputation every few seconds. Economic dispatch is usually somewhat slower, say every five minutes. The question arises as to what should be the lead time of the weather predictions.

A weather prediction about one day ahead would be sufficiently accurate for the purposes of generation scheduling or unit commitment. The choice of which generators to use, and the time at which they are expected to be needed is normally determined about a day in advance. This means that a weather forecast made a day in advance would be in time to be factored into the generation schedule. The accuracy of the forecast might depend on the geographical area and the season of the year, but presumably the effect of forecast errors would be understood well enough to devise an adequate schedule.

However, such a schedule may have to be somewhat conservative. It would be poor operating practice to run too high a risk of a generation shortfall because of errors in the weather forecast. On the other hand, too conservative a schedule could be expensive if too high a reserve margin results.

If the area contains generators that can be brought up and synchronized rapidly, there might be an economic advantage to using a non-conservative schedule together with a shorter term weather forecast.

Very short term forecasts may be factored into the economic dispatch computation, if the percentage of load met by DSGs is high enough. Exactly how such short term forecasts would be obtained, or how they would be included in the economic dispatch calculation remains to be worked out.

In most systems, an abrupt load change or loss of generation will be accommodated by changing the power outputs of the regulating units, under the control of the AGC system. Subsequent recalculation of the economic dispatch settings for the system will usually result in the changed loading being redistributed, and the regulating units returned to previous settings. It is conceivable that some of this double duty of the regulating units can be obviated by an appropriate combination of AGC, DSGs and economic dispatch. In fact, the economic value of using controllable DSGs for load-following is an area worthy of further study. This is especially so because some DSGs will not suffer an increase in operating and maintenance costs by being used this way, since they contain no moving parts.

A further consideration is the likelihood that as computers become faster and computational algorithms become more sophisticated, the functions of AGC and economic dispatch will be merged to form more efficient control strategies. These strategies could include as a part of their objectives the minimization of regulator control action, particularly for generators that incorporate servo loops with inherent wear-out mechanisms. Control response to transient or rapidly varying loads could thus take into account the cost of undue control action as well as steady-state economic considerations.

E. VOLTAGE CONTROL

Voltage regulation is not usually considered alongside automatic generation control and economic dispatch. However, voltage control is a feature of some DSGs which gives the system operator another variable over which he has real-time control. Actually, since most customers are connected to the distribution system, voltage control is generally more important here than at the bulk level.

Voltage regulation and VAr generation are closely related functions that involve the entire utility network from bulk generation plants to feeder lines. There are several objectives of these functions in addition to the obvious one of supplying power to the customers at a fairly tightly controlled voltage. These objectives include supplying the customer with the required VAr demand, maintaining network elements such as generators, transformers, and transmission and distribution lines within their voltage and current ratings, providing adequate stability margins for the operating system, and doing all of the foregoing at minimum cost.

A number of approaches are available to provide for control of VAr flow and regulation of system bus voltages. Variation of field excitation on a generator controls the internally generated voltage, sometimes known as voltage behind synchronous reactance, which largely controls the flow of VArs into the utility system. Adjustment of the field excitation thus provides a smooth (stepless) control for VAr injection at the bulk generating plant.

A synchronous condenser is another means of controlling VAr injection into a power network. This is essentially a synchronous motor operated without a shaft load but with variable field excitation. Adjustment of the field provides a continuous change from lagging to leading VArs as the field is increased. Synchronous condensers are relatively expensive and are, therefore, used where it is possible to take advantage of the economy of scale. They are found in very large installations where smooth control is desired.

Alternatively, the generating units in gas turbine peaking plants or in hydro pumped storage installations may sometimes be used as synchronous condensers. For gas turbine peaking units, a clutch may be provided to decouple the turbine from the alternator to minimize windage losses. Declutching is impractical for large hydraulic turbines because of the torques involved; an approach that has been used instead is to pressurize the turbine chamber with sufficient air to evacuate the water, and operate the alternator with the turbine running in air. With these configurations, the cost penalty for providing synchronous condenser capability is relatively small, although clearly the capability does not exist at the same time as the units are generating real power. Such methods are of little value at time of system peak.

Load tap-changing (LTC) transformers may be used to assist in voltage control at the bulk supply, transmission, sub-transmission, and distribution levels. Normally, fixed-ratio transformers are used on the feeder and lateral lines because of their lower cost. Typically, voltage increments on the tap-changing units are on the order of one-half percent. Line regulators (inexpensive auto-transformers that can buck or boost the line voltage) are also used, and similarly provide a range of a few percent in increments of about one half percent.

Shunt inductors may be used in a utility to provide additional lagging VArs for loading transmission lines and restraining the voltage rise under light load conditions. The inductors may be switched individually or may be equipped with taps to provide finer control of the VAr flow. The use of inductors is generally confined to the transmission and sub-transmission portions of the utility network.

Recently an extension of the inductor approach has been developed that uses thyristors to provide duty-cycle or phase control of the inductor current. These devices are known as static VAr supplies (SVS). In an SVS, the VAr flow

in the inductor can be varied smoothly from near zero to its maximum value, thus providing stepless control of line voltage. Harmonic filters are generally required with SVS to reduce the harmonics injected into the power system.

Capacitors are used throughout the utility system to provide leading VArs for line voltage control and for load power factor compensation. These will be discussed further in Section IV.

F. THE EFFECTS OF DSG ON VOLTAGE CONTROL

Voltage control on large generators is constrained by consideration of their auxiliaries, which are normally supplied by transformers connected at the generator output. Voltage control on the transmission system is usually governed by consideration of the production or consumption of reactive power in the transmission system through the daily load cycle. The addition of DSGs with voltage-control capability does two things. First, it adds flexibility to the operation of the system, and allows for increased independence of the consumer voltage and the load cycle. Second, it could be used to supplement existing voltage control means during a brown-out. This particular aspect of DSG voltage control would have to be considered with particular care. Depending on the nature of the local load, voltage reduction by a DSG might result in load being picked up by the balance of the distribution system, or might result in an unacceptable reactive demand by the DSG.

The question of DSG voltage control, and its coordination with existing distribution system voltage control methods is worthy of considerable study. Most DSGs have the capability for voltage control (see Section II), although some are operated in a maximum power tracking mode, at least according to early designs.

If a DSG has independent voltage control capability (corresponding to an exciter in an alternator), it can and must be operated cooperatively with any method of voltage control on the existing power system. If the DSG is small, perhaps this can be done by local measurements and local control alone. Keeping the generation or consumption of reactive power within reasonable limits may be a sufficient control algorithm.

As the DSG rating gets larger, the opportunity to use it to help control the voltage on the distribution system must not be overlooked. In order to accomplish this, coordination between the DSG controller and the voltage control methods in use on the distribution system becomes unavoidable.

Voltage control on DSGs equipped with maximum power controllers raises some interesting questions. Independent voltage control is always possible, of

course, with the addition of variable-ratio transformers to the DSGs. Such a step might represent an intolerable additional cost. A maximum power controller attempts to provide a sort of match between the source and the load. In the case of photovoltaics (the most likely user of maximum power tracking controls), the characteristics of the cells are such that the maximum cell current varies with insolation, the voltage being more or less constant. The maximum power controller is faced with the problem of extracting as much current as possible from the cells (without causing the cell voltage to drop abruptly; the I-V characteristic is very nonlinear) and converting it to alternating current at the prevailing line frequency and prevailing line voltage. Since frequency and voltage will vary somewhat, the controller design is clearly not a simple task.

But design complexity should not deter us from making the proper design decisions. Whatever the size of the DSG, some means of voltage or VAr control must be provided. If a DSG is large, its voltage control should be coordinated with that of the distribution system, and other DSGs. The desire for a maximum power output from the DSG (motivated by economic considerations) is not inconsistent with the system need for coordinated voltage controls.

Voltage control on DSGs can be used to change the reactive demand on the system, and it can be used to control the voltage at the consumers' terminals, although not independently. Because of its dual use, voltage control is included in the discussion of the changes at the ECC. It might be argued that the coordination of distribution system voltage control and DSG voltage control occurs outside the ECC. One possibility is that voltage control will be an option available to the ECC operator, perhaps only of interest in time of system emergency. At other times, the various distribution system voltage controllers go about their business without operator intervention.

Another possibility is that the DSG can be used to control VAr flow, in a way coordinated from the ECC. In some cases, the DSG voltage control capability can be used even when the DSG is supplying no real power.

Most transmission systems generate an excess of VArs at night, when they are lightly loaded. Some DSGs are typically non-productive at night (for example those depending on the sun or wind) but they may be used as synchronous condensers or, more accurately, synchronous reactors, to absorb the leading VArs generated by the system. For example, some types of inverters can be short-circuited on the dc side and used as variable reactors with maximum VAr generation equal to the power rating in normal use.

The possible use of DSGs to control VAr flow in this way should be of particular interest in the case of DSGs connected into the subtransmission system or at the distribution substation. It might be worthwhile to consider this concept when some aspects of the DSG control system are being designed.

G. SUMMARY

1. The Most Commonly Performed EMS Functions

AGC, economic dispatch, and VVC are control functions performed in real time by an EMS. Protection is a real time function performed throughout a utility network ' an independent system. State estimation, on-line load flow and security monitoring are ongoing activities which support the above real-time functions.

2. DSG Affects Mostly Real-time Control Functions

AGC, economic dispatch and VVC are expected to be significantly affected by a high penetration of DSG. Protection is also affected, primarily at levels at or below the distribution substation.

3. AGC System Designs Tailored to Large Bulk Supply Plants

Present AGC systems accomodate a relatively small number of large bulk supply plants with a few generating units at each plant. Although the computation may be quite complex, the limited total number of machines in the system permit the computations to be performed with modest computer capability.

4. Simplification in AGC Control Techniques Needed to Accommodate Large Number of DSGs

The use of segmented straight-line approximations to generation cost curves permits use of relatively simple logic for controlling DSG power generation. Control of a great many DSGs might, thus, be accomplished by a number of microprocessors located at relatively low levels in a utility, such as distribution substations. This would ease the computational load on the energy control center.

5. Power Regulation Performed by Only a Portion of Machines in a System

Considerations of machine thermal stresses and generation economics may dictate that certain types of generating units be operated at a fixed, or base load. Other units with more flexible load rate capabilites must then handle the major portion of the short-term load variations. Still another type of generating unit with very rapid turn-on and load change capability may be used for very short-term load changes.

6. DSG Effects on Power Regulation

The inclusion of non-schedulable or non-controllable DSGs will tend to increase the power regulation demands on a utility, since the reaction will be similar to an increasingly variable load. On the other hand, controllable and schedulable DSGs can assist a utility by providing improved local power regulation, decreasing the regulation demands on the remainder of the system. These DSGs may also provide improved capability for control of transmission line loading.

7. Weather Predictions Presently Used in Load Forecasting

In addition to the effects on utility loads of diurnal and annual insolation variations, large-scale weather patterns may be taken into account in predicting load characteristics. This would normally be included in generation schedules for bulk power plants.

8. Macro-weather Prediction May Be Used in Generation Scheduling of Some DSGs

The operation of some DSGs, particularly those dependent on sun or wind, may benefit from the inclusion of large-area weather predictions as an aid in the scheduling of DSG power capability. This is analogous to the use of weather predictions in estimating variations in load.

9. Devices Presently Used for System Voltage/VAr Control

Generator field control, static VAr supplies and synchronous condensers are generally used at bulk generation or transmission stations. Tap-changing transformers and shunt inductors may be used at fairly high levels in the distribution system. Shunt capacitors are likely to be used throughout the distribution system.

10. Effects of DSGs on Voltage/VAr Control

The incorporation of controllable DSGs into a utility provides an additional degree of flexibility of voltage control in the distribution system, and therefore can assist in maintaining constancy of line voltage during load variations. It may be possible to control small DSGs by using only local information; large DSGs would probably require control inputs from the energy control center. Some DSGs may also be able to provide assistance in control of reactive power flow, thus supplementing the action of other devices controlled by the ECC.

Unless the DSG is very small compared to the system to which it is connected, some form of voltage/VAr control is considered essential.

SECTION IV

CHANGES OUTSIDE THE ENERGY CONTROL CENTER

A. BACKGROUND

A knowledge of today's system is necessary in order to understand the possible changes in hardware that may occur outside the control center when DSGs are added. These changes will have characteristics that are not only functions of the particular type of DSG that is implemented, but will be, to some extent, dependent on the point in the system at which the presence of the DSG is primarily sensed. This may be at the sub-transmission level, the distribution substation level, or even at the customer's own location.

In order to develop some rationale for requirements in the hierarchical environment that will adequately meet the needs of the utility as it now operates and as it can be expected to perform with integrated DSG, it is necessary to consider some of the physical aspects of power systems and of control systems. The principal physical parts of any power system that will affect control system design are transmission and distribution.

B. TRANSMISSION AND DISTRIBUTION

In the early days of the electric power industry, transmission, as it is understood now, was virtually non-existent. Electricity was generated in a small power station and transferred no more than a few city blocks to the load. However, as more and more customers were connected, the increased demand was met by building separate large stations, rather than many small ones. It was an economically sound choice. These new stations with correspondingly larger capacities meant that electricity had to be fed over longer and longer distances as the demand continued to increase. The improved efficiency and lower capital cost per kilowatt of the larger generators was termed economy of scale. This arrangement further allowed for increased benefit from diversity among loads. Such diversity remains as one of the key factors which make larger electric power systems more economical than stand-alone, customer-owned generation and distribution.

The economy of scale of generating plants then was matched by a corresponding improvement in the efficiency of the system used to transmit power to loads. The **transformer** allowed the generation voltage to be stepped up for higher transmission line voltages and then down again for use. At the same time the I^2R losses of transmission were dramatically reduced because for the same power, just doubling the voltage will halve the current, and thus the I^2R loss is cut by a factor of four.

Most utilities operate both transmission and distribution systems, and many of them have defined a threshold voltage above which the system is termed transmission. The actual choice of this threshold voltage varies between companies and is somewhat arbitrary. The distinction between the transmission and distribution segments of any power system is also demonstrated by a difference in the basic operating philosophy. Generally, a transmission network is used for bulk power transfers across an entire operating area while a distribution system is used to deliver the energy to the loads. Therefore, generators, especially those with large capacity, are normally connected to the transmission system; only rarely have generators been connected to the distribution system and only rarely have loads been connected directly to the transmission system. For reasons of reliability, almost all generating stations have more than one power line carrying their output to the transmission network. If a generator fails at a station, other units can make up for the power loss without undue disturbance. If a line fails because of accident, weather or natural disaster, then the remaining lines are readily available to carry the load. Such a system is designated as interconnected and this is one of the key characteristics of transmission.

On the other hand, distribution systems employ quite a different organization. Power is supplied to the distribution system from a bulk supply station. These distribution stations convert the power by transformers to supply feeder lines which in turn supply the distribution transformers and low voltage lines that deliver power directly to the customer. These feeders usually operate in a radial manner, so that if one fails, there is normally no way to continue to meet the customer requirements; the customer experiences a power outage. It is prohibitively expensive and not a common practice to provide an interconnected distribution network that would overcome these outage problems. The exception is the intracity grid.

To illustrate some of the points of the foregoing discussion of interconnected transmission and radial distribution, it is of interest to note the experience of the Central Electricity Generating Board in England (CEGB) over many years of integrated system development. The CEGB is one of the largest and oldest integrated systems in the world. In 1926, plans were laid to form a National Grid[1] which would operate at a voltage of 132 kV.

The system was constructed between 1928 and 1933, interconnecting selected generating stations and enabling the creation of a pool of spare generating capacity. The method provided more effective use of the most efficient generators and was a significant factor in maintaining the integrity of the electricity supply during World War II. By the late 1940's, it was evident that a higher system voltage was needed, so a new design operating at a voltage of 380 kV with a temporary intermediate step of 275 kV was planned. This system was to be superimposed on the older 132 kV system. When voltages on

---

[1]The name Grid is rarely used to describe a power system, and is not generally acceptable to the majority of power system engineers. The National Grid is one of the exceptions.

the intermediate 275 kV system were analyzed, it was found that a 5% voltage tolerance could be achieved. This was better than had been originally thought and led to increasing the normal level in the 380 kV system to 400 kV. The 275 kV system is now all converted to 400 kV and 275 kV is now no longer operational. The 400 kV system permits bulk transmission of energy to exploit economic generating plants and interconnection of load areas for system-wide pooling of both generation and demand, leading to a reduced level of reserve generation in each area.

The 132 kV system was subsequently operated in a less interconnected way, and no longer called the National Grid. It was reclassified as part of the distribution system and its operation turned over to local Area Boards responsible only for distribution of electrical energy. Such a voltage (132 kV) would be regarded as too high for distribution by most U.S. utilities; it would generally be regarded as a sub-transmission voltage level.

This upward climb of high voltage transmission levels, 132 kV to 275 kV and now 400 kV illustrates a widespread trend towards higher and higher transmission voltages. Figure 4-1 indicates how transmission voltages in the U.S. and Canada have progressed since the inception of power systems. The highest voltage in normal use anywhere today is the 765 kV on the American Electric Power System, while several test lines of even higher voltage are in use and/or under construction. The upward trend is expected to continue.

While the trend of transmission voltage is generally upward, the voltage at the consumers terminals is more or less fixed. Electric utilities cannot serve loads at other than agreed upon voltages, so that the safety and efficiency of customer owned equipment can be assured.

In spite of this, there is a remarkable diversity of ways of distributing electric energy. Since DSGs will be connected to the distribution system, this diversity complicates the task of assessing the effect of DSG. A few examples will illustrate the diversity of distribution system design.

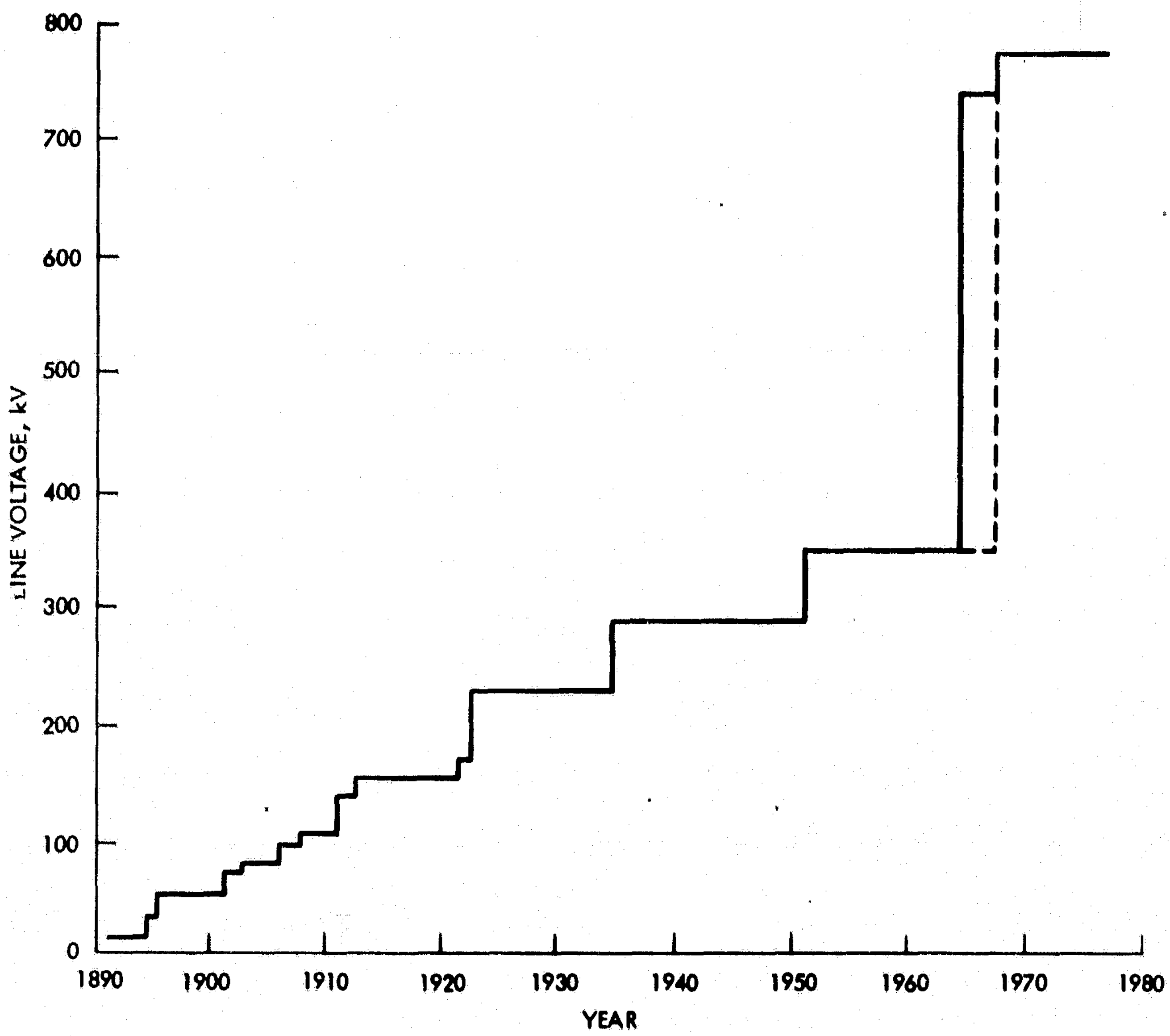


Figure 4-1. Highest Transmission Voltage
(USA and Canada)

C. EXAMPLES OF DISTRIBUTION SYSTEMS

In London, bulk supply is brought in at 132kV or 66kV through transformers of about 200 MVA total capacity. This substation is described as a capital substation. Stations like this supply main substations at 33kV, with banks rated at about 50 or 60 MVA. From here, an 11kV open ring system feeds transformers of about 500kVA to 1 MVA which supply the 415/240V three phase system. In central London, the lowest voltage part of the system is networked or highly interconnected.[1]

The 11kV rings could offer higher security of supply if they were operated closed, but require zone protection between adjacent transformers in the ring. This, in turn, would require automatic switchgear, which is expensive and necessitates regular maintenance. In the absence of bus-zone protection, a busbar fault in the 11kV side anywhere in the ring would bring down the entire ring. Automatic supply restoration by reconfiguration is not practiced, because of the expense, particularly of the high voltage switchgear.

In Chicago, supply is taken at 138kV and 69kV, and fed to an entirely underground (in downtown) distribution system at 12.5kV or 4kV. Networks are also used here, with loads/network in the order of 600 MW.

Utilization voltages are 120/208V (three phase) and 277/480V (three phase). Outside the downtown area, supply is largely by 12.5kV radial feeders (overhead) with utilization voltages of 120/240V (variously described as single phase or two phase).

Networks are supplied by transformers rated between 500kVA and 2.5 MVA with primary disconnects. The 12.5kV lines are equipped with circuit breakers.

In New York (Manhattan) most of the load is fed from 120/208V and 265/460V interconnected networks. Supplies to its network transformers are at 13.8kV. Interestingly, New York had some generation on its 13.8kV system as recently as the late 1960's ,although the load is now supplied through area distribution substations fed at 69kV or 138kV from the transmission system.

In most urban areas and in all non-urban areas in the United States, a purely radial distribution system is employed. In the non-urban areas, small transformers each supplying only a few loads are employed. In urban areas, there is a range of practice depending on the amount of load at a customer and

---

[1]This, by the way, is properly called a grid. Such a grid, and the British National Grid, are the only examples in which the word grid should be used to describe part of a power system.

the local load density. These distribution transformers may be pole-mounted, pad mounted or below ground, and are typically sized at only a few tens of kVA. Distribution systems of this type are by far the most common type in the United States. It is therefore worthwhile to describe these systems more fully.

Bulk supply may be taken from the subtransmission system at, say, 69kV and transformed down to a level in the region of 12-13kV. This level is known as the primary feeder voltage. Primary feeders are usually three-phase, four-wire. Single-phase laterals are supplied from the primary feeder. Single phase transformers on the laterals are used to supply residential loads. By taking advantage of diversity, the fact that not all loads of the same type are actually coincident in time, the transformers can be rated below the total of the individual maximum demands of the customers' services. Radial feeders of this type are not as reliable as distribution networks, since the entire load is lost when the feeder breaker trips. Reliability is sometimes improved by using emergency interconnections to adjacent primary feeders. This lessens the duration of the outage, but an outage still occurs.

Shunt capacitors are sometimes used for distribution voltage control. Such capacitors may be single-phase or three-phase and can be used on the primary side (≈12kV) or on the secondary side. Suitably switched, shunt capacitors can be used to replace or supplement feeder voltage regulators or load tap-changing transformers. Control is generally by time clock or voltage, or a combination of both.

The requirements for connection, and the impact of DSGs on distribution system design and operation will obviously be as varied as the distribution systems. Connection to a networked system must be different from connection to a single distribution transformer. Protection coordination will depend on the kind of protection in use on the primary side, and whether fuses, circuit protectors, or breakers are used on the secondary side.

D. CONTROL SYSTEMS

With the physical differences between transmission and distribution now clearly established, and with the definitions, functions and requirements of an EMS presented in Section I, it is quickly evident that most of the control hardware to perform the EMS tasks is concentrated in the transmission portion of a utility. There has been little need to extend the use of control mechanisms below the distribution substation level. That occurred principally because most of the control actions required were focused on the generating stations and on the high voltage interconnecting systems. It would be very difficult to attempt to apply frequency control techniques anywhere other than at the source. The relatively small quantity of control points for voltage adjustment in the transmission system makes it easier than using extensive and possibly less reliable control equipment dispersed throughout the distribution

network. Since it was also necessary for the bulk power supplier to maintain the integrity of the power system, it was logical that a central control location be established into which would flow the monitoring and other operational data for day-to-day and minute-by-minute control. From such a central point, the necessary control commands could then be determined and implemented virtually automatically.

However, newer, more reliable, more compact and less expensive control and computer equipment is continuously being made available. It provides the utility companies with the opportunity to re-evaluate system engineering for the control and delivery of their product. Further impetus has been given by the introduction of load management. Although some utilities have already made considerable investment in equipment for this purpose, it remains a comparatively new technological field with a wide choice of applicable techniques and goals. One of the most important effects, at least as far as this report is concerned, is that load management has caused the introduction of simple control devices throughout the distribution system. For the most part, the systems have employed one-way communication channels to deliver a command to a relay or switch, but a significant number of two-way communication systems are now appearing that would enable other features of control and monitoring to be exercised. Remote meter reading, time-of-day metering as well as the control switching of customer devices, such as heating and air conditioning, are examples of new functions that can be reliably and economically integrated into the power system.

DSG is about to enter this kind of environment. As previously stated, its impact will depend not only on the current control status of the utility involved but also on the point in that system at which the particular type of DSG is to be interconnected. Such an impact is best analyzed by a re-examination of the requirements which the hardware must now accomplish. A series of diagrams was used to enumerate sets of requirements at the principal points in the EMS. To establish the appropriate relationships, interfaces and other detail, the model simplified power system of Figure 4-2 was used.

This figure indicates the parallel structure that can be expected between the power system hardware hierarchy and the control system hierarchy. The power system hierarchy exists. The top of the control system hierarchy shown in Figure 4-2 also exists in the central EMS of today. The remainder of the control hierarchy is, however, but one of a number of possible hierarchies that might occur. Some others will be discussed briefly later in this section. The figure is not dissimilar to one of the arrangements shown in a recent report which considered the control of DSG as a system decomposed into three or four levels (Reference 2). In each case, the top level is the central ECC and the lowest level is the DSG controller. One or two other levels are inserted between these two, and these added levels have a counterpart in the power system in many utilities.

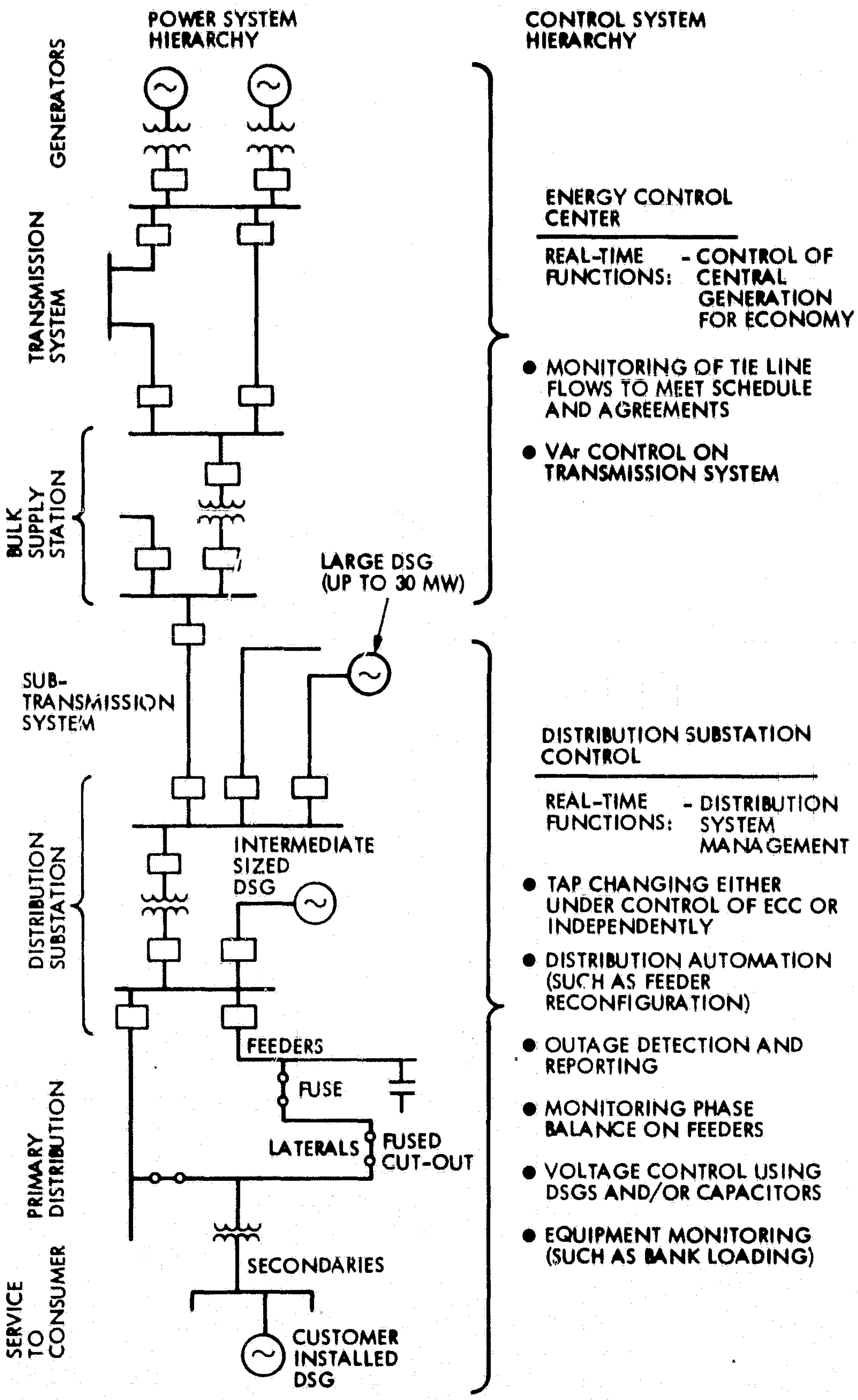


Figure 4-2. Simplified Power System, Showing Possible Parallel with Control System Hierarchy

An EMS, from the control center to the DSG controller, includes the acquisition of data for control, and the furnishing of information for planning and design. It takes into account those institutional issues which affect decision making, the provision of reserve margins, and other policies and procedures. The real-time aspects of EMS operation in the structure of Figure 4-2 are distributed throughout the power system.

The activities of the ECC, the central controller of the power system, encompass the management of all generation equipment within the area of control; control of the power exchange to/from external areas; diagnosis and the correction of system electrical problems; and recording of data pertinent to system operation, diagnostics and cost billing.

The primary activity of an ECC is to ensure that a reliable supply of electric power is delivered to the customer at the minimum system operating cost. The functions implemented at the ECC to meet this objective were discussed in Section I, and the impact of DSG was discussed in Section III.

E. SUBSTATION CONTROLLER

An additional level of distributed control can be inserted at the distribution substation. The control performed from this location falls into two categories; control using local intelligence only and control which is based on inputs from a higher authority within the control structure. In all probability, most controlled hardware will be operated in accordance with a priority system which establishes whether local control acts alone or in accordance with centrally-computed instructions.

In a system with distributed intelligence, two important features of the control system, information processing and decision making, may be local or centrally located. The central controller, located at the ECC, has information available to it concerning the entire system. It can process this information and issue commands based on its decisions. The local controller, on the other hand, has available to it local information not available at the ECC. Its decisions reflect local conditions.

For example, local control (using local information to close feedback loops) could operate tap changers on the distribution bank, and switch feeder capacitors so as to maintain consumer-side voltage within some narrow range. However, in time of system emergency it might be necessary to reduce the system voltage, in which case a command from the energy control center would take priority. Very likely such a command would be essentially open-loop. Reliance would be placed on the local controller to execute the voltage reduction, the details of the control action being too trivial to burden an ECC. In this way the command could be issued to many distribution substations, without regard for their individual arrangements of hardware, etc.

However, the highest priority need not always be at the highest level in the control structure; a properly coordinated system would permit the substation control to recognize local constraints or requirements. For example, there might be a life-support system on a feeder: this would be a reason for local control to override a central instruction. Local knowledge of DSGs and their state is essential for this coordination to be effective. Little would be gained by having the DSGs controlled from a more remote location than the closest distribution substation.

The controller at the distribution substation is doing two things. First, it is controlling and monitoring local hardware using local information. To do this, it must interface with a variety of switches and regulators and must interact with DSGs (if controllable) connected at the substation level or below. Second, the distribution substation controller must interact with the next highest level in the control hierarchy, process its commands and if appropriate pass the information through to the devices in its area.

Of course, the information passed through a distribution substation controller can be modified considerably by the controller in the process. For example, the signal from the ECC might be a bit-string representing the command "decrease load one notch". The result could be a tap-change operation, an increase in output from some DSGs, or limited load shedding. With the system shown in Figure 4-2, each distribution substation within the ECC control area would make its own decision as to how to implement the original instruction. It seems that this is an excellent use of local information and local intelligence. A configuration in which the control system essentially parallels the power system in this way is worthy of further study. It is also likely that this approach would minimize interlevel communications and provide for more effective system operation in the event of temporary communication problems.

F. CONTROL SCHEME FUNCTIONAL REQUIREMENTS

The functions and interfaces required of the various elements of the energy management system can be conveniently summarized in diagram form.

The diagram in figure 4-3 shows the energy control center. Interface with a higher level in the control hierarchy such as regional co-ordination is not shown; instead the figure indicates how some aspects of the ECC should be responsive to the objectives of system management. Since it is from these objectives that the activities of the whole energy management system ultimately derive, it is convenient to show the ECC activities in the same diagram.

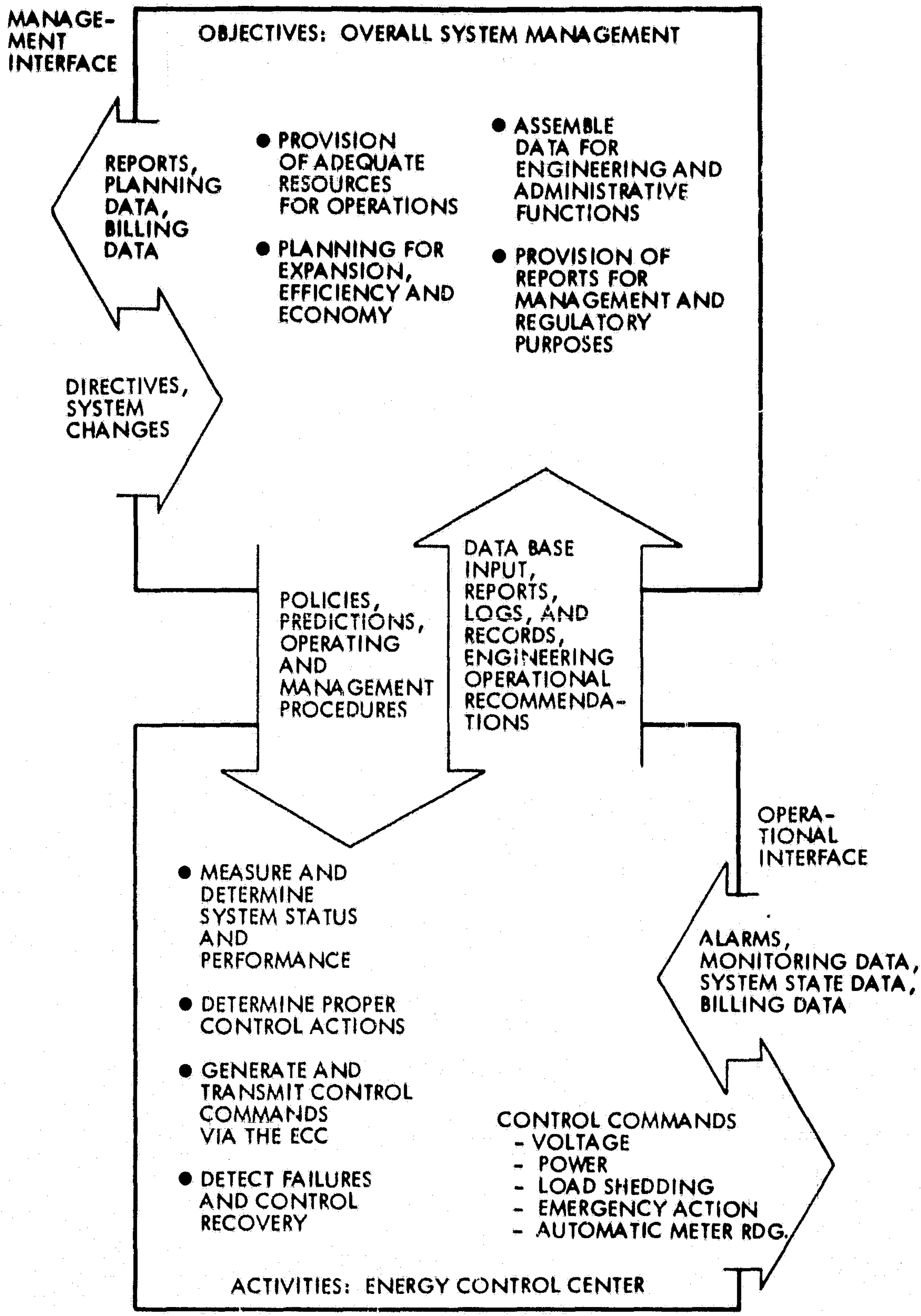


Figure 4-3. Functions and Interfaces of an Energy Management System

Energy control centers exist: they are primarily concerned with system frequency and voltage, and their functioning was described in Section 1. The next lowest level in our assumed control hierarchy for DSG is the distribution substation. Control systems do not ordinarily exist at such locations at present. Consequently, the appropriate diagram contains somewhat speculative entries. Figure 4-4 shows the functions and interfaces for a controller at the distribution substation.

Looking down the hierarchy from the substation controller, there are interfaces to the distribution substation itself and also to the distribution system. A variety of control functions could be implemented at the substation, including distribution automation and DSG control. If there is a DSG at the substation in question, its control and monitoring requirements would be defined in terms of the interface to the substation.

DSGs could be located on the distribution system outside the station. Figure 4-4 shows such DSGs as being operated through a separate interface. In a hardware sense, there might be more than two interfaces. The difference between the two interfaces shown is one of location, but such a distinction may have little practical significance.

Looking up the control hierarchy, the substation controller sees the energy control center. Traffic across this interface will consist principally of downcoming commands and upgoing alarms and state data.

At the bottom of our hierarchy is the controller at the DSG itself. The complexity of this control system will vary from DSG to DSG. Figure 4-5 shows the diagram for this control system in a generic sense, indicating an upwards interface to the distribution substation controller. In a downward direction are the actual hardware elements to be controlled at the DSG.

In some cases, for very small DSGs, the controller can be very simple, and it could be that no external control is carried out. On the other hand, the DSG could be quite complex, and require a control system of corresponding complexity. Figure 4-6 shows an expansion of the control requirements indicated generically in Figure 4-5. Figure 4-6 is an example of a typical cogenerator.

Diagrams such as the sequence from Figure 4-3 to Figure 4-5 are useful in defining functional and interface requirements. The interfaces between diagrams must be made to match; an exercise which may be productive in itself. The communication requirements readily follow once functional requirements have been expressed in appropriate terms.

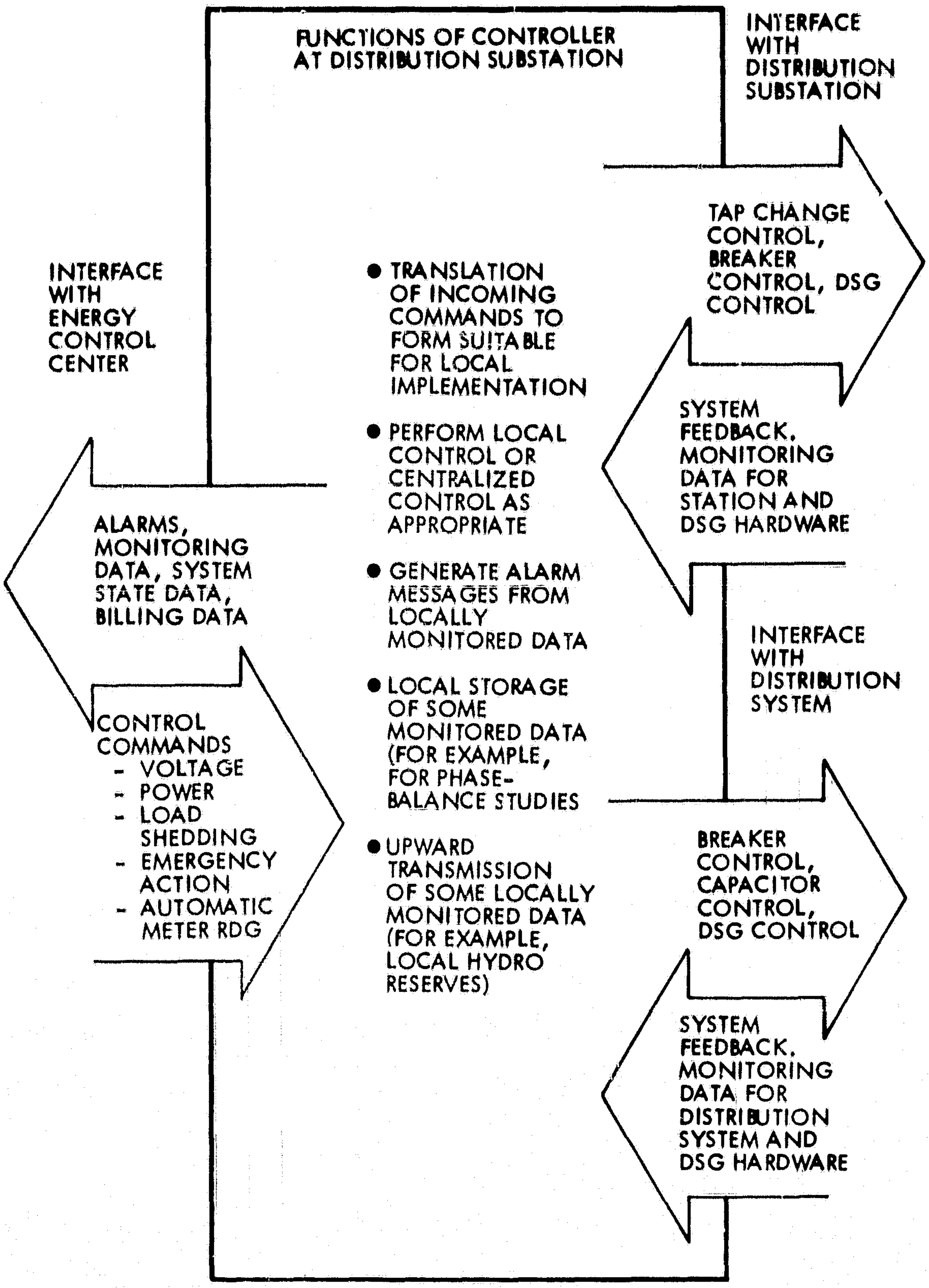


Figure 4-4. Functions and Interfaces of a Controller at the Distribution Substation

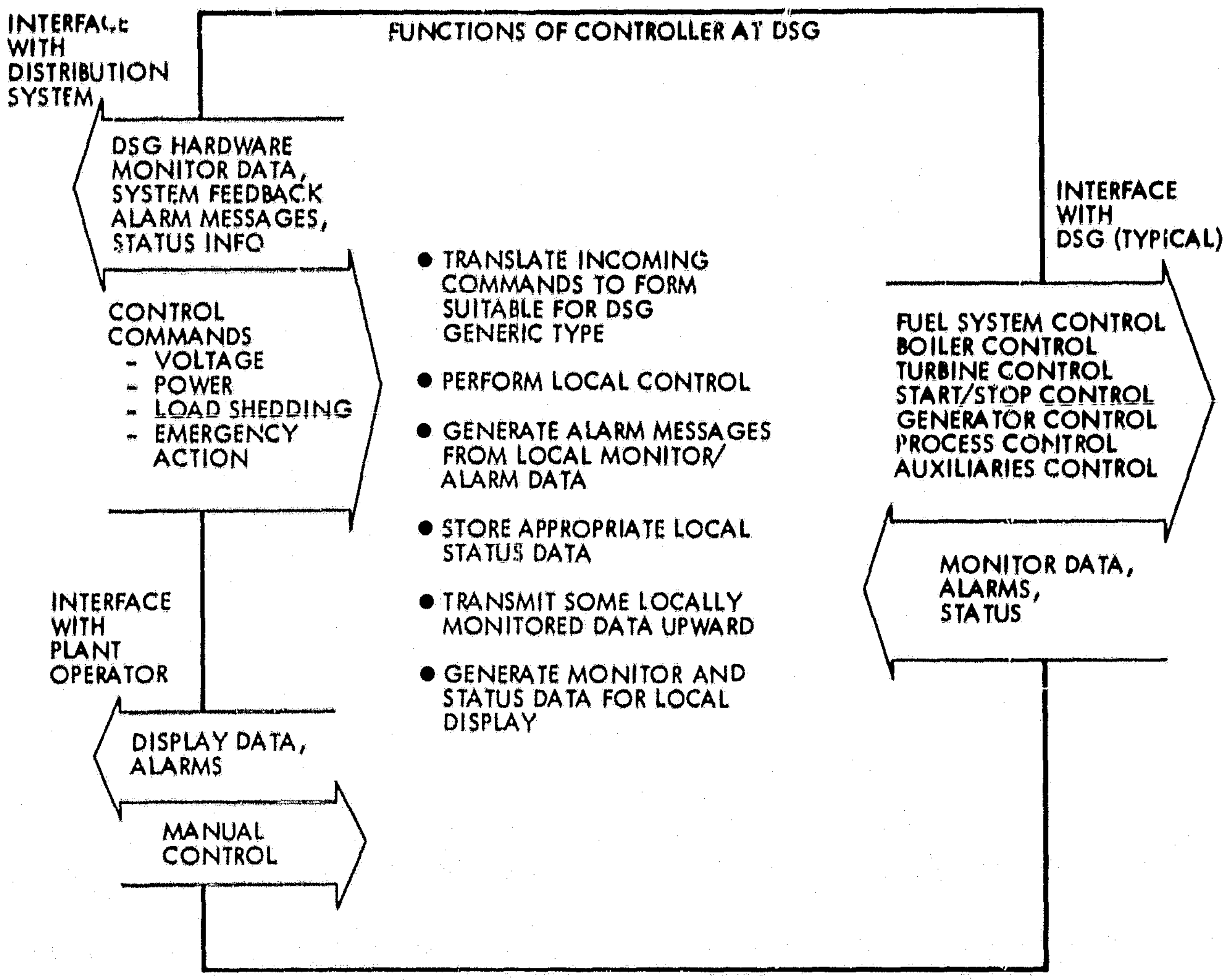


Figure 4-5. Functions and Interfaces of a Controller at a DSG Location.

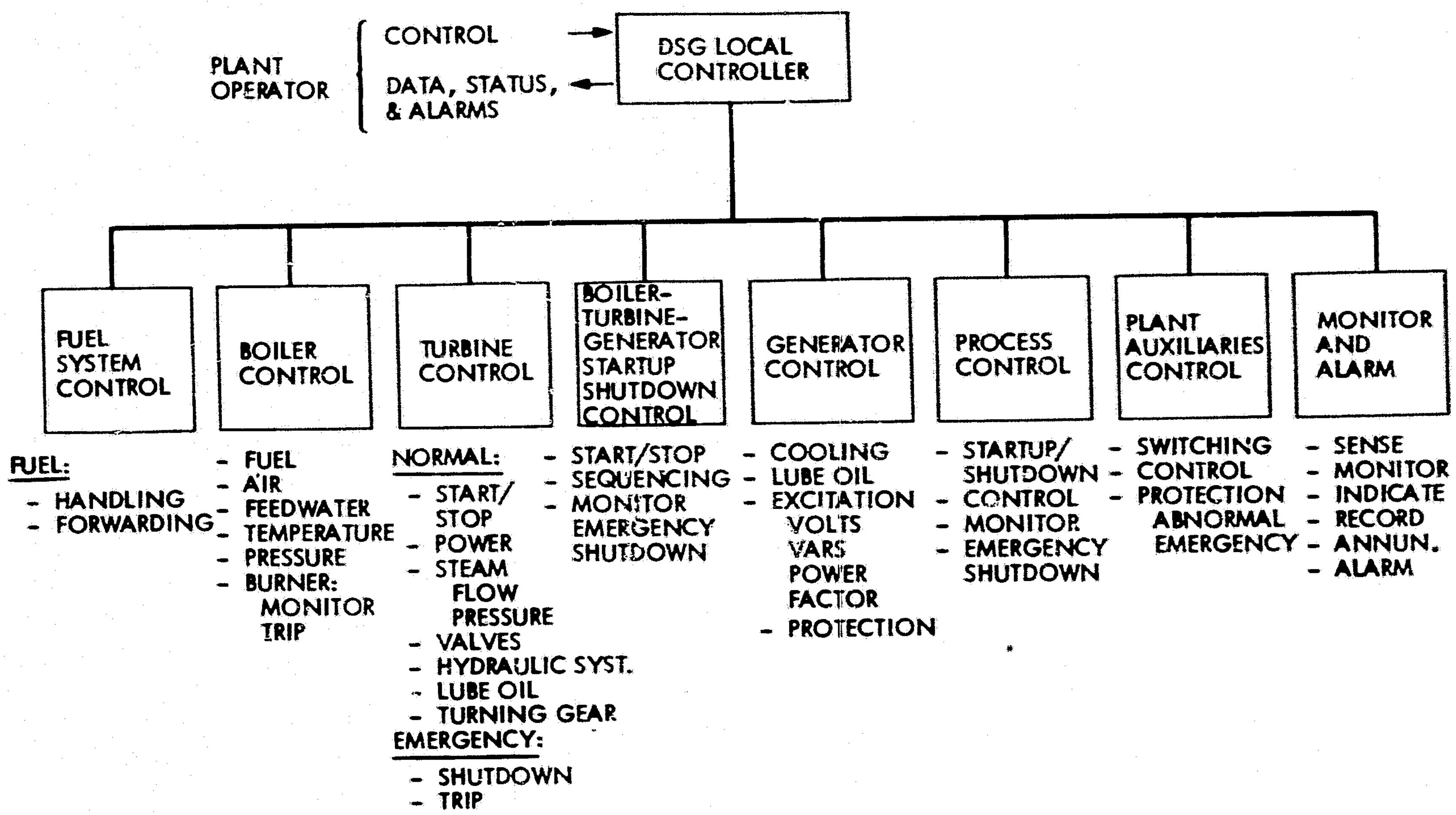


Figure 4-6. Expansion of DSG Functional Requirements for Control - a Typical Example: Cogeneration Plant System Control Functions

In the energy management system discussed above, the top level of control has been the energy control center, and the bottom level the DSG. One level of control was inserted between these extremes. It showed how the diagrams could be used to divide the workload and define the necessary interfaces.

Other hierarchical arrangements are possible. This topic is taken up in the next subsection.

G. ALTERNATIVE HIERARCHIES

So far this report has discussed a hierarchical control system with a central controller located at the ECC, with a controller at the DSG and with one intermediate level of control inserted at the distribution substation. Clearly, other arrangements are possible.

Assuming that the DSG itself has a controller of some sort[1], then the minimum number of levels in an energy system with DSG is two; one at the ECC and one at the DSG. The advantage of adding intermediate levels is that the control and communication burden imposed on the central controller is reduced. For example, the ECC should not have to handle any detailed information concerning a DSG of the complexity shown in Figure 4-6, yet some information probably should be made available concerning the state of cogenerators or hydro plants. The information can be filtered by the intermediate control levels.

In a trivial sense, the upper bound on the number of levels in a hierarchy is set only by complexity of the power system. However there is no practical reason to approach this upper bound. There is no point, for example, in putting an intelligent controller at a location already covered by the ECC. There is also no point in putting a controller at a location where there is nothing to control. While these two conditions will vary from system to system, it is fair to say that most control centers are responsible for the system as far down as the subtransmission level, and that at some intermediate substations there would be nothing to control, that is no LTC transformers and no capacitors.

Thus, for example, there would be no point in locating a controller at a residential distribution transformer. While there are quantities that could be measured there, there is no hardware that could be controlled.

---

[1]This controller need not be intelligent, and it may not always be connected as part of a control hierarchy, but most DSGs require some form of local control.

It seems that the lowest level at which control may be fruitfully exercised is higher than the residential distribution transformer. The highest level which does not overlap the existing control system entered at the ECC is probably the distribution substation or the bulk supply station.

Between these two extremes is a rather narrow band of possible locations for intermediate control. In all probability, it would make little difference if the intermediate level were not located precisely as in our example. Any reasonable alternative would lead to a similar set of functional requirements since the latitude in choice of location is so small.

From an installation standpoint, the incorporation of the local controller at the substation poses no particular problems. Generally, the substation will have enough room to include the relatively small controller without requiring additional real estate or structures. Furthermore, the substation is likely to have sufficient standby power (usually batteries) available to power the controller during a power outage, permitting it to continue to operate and possibly assist in recovering from the power outage. Communication lines or equipment may already exist that can be used for routing information to and from the ECC.

H. PROTECTION

Protection is considered separately since its actions are fundamentally independent of the remainder of the energy management system, although the results of its actions (breaker operations for example) may be communicated to the energy control center. Protection is impacted by most of the attributes of DSG.

Historically, protection systems arose for the purpose of preventing equipment damage in the event of system faults. It was quite a straightforward matter to use the increased current which flowed into a fault to trip a circuit breaker or open a fuse. This expedient approach to protection used the fault current itself or a replica of it to provide the **information** on which to base a trip decision and at the same time to provide the **energy** to operate a relay.

Protection of radial feeders is generally by breakers or reclosers at the distribution substation, tripped by action of an overcurrent relay. Protection of laterals and transformers is generally by use of fuses, including current limiting types. The presumption behind selection of protection has been that the sources of fault current (other than a relatively small amount from rotating equipment loads) is at the distribution substation or higher. Thus, protection to date is based on there being no source, or the equivalent of a source, on the feeder itself.

From the point of view of DSGs, history may have left an unfortunate legacy. Many of the DSGs which could be put on the distribution system will not provide overcurrent in the event of a short. Because the control systems of such DSGs are designed to be non-linear, some devices would continue to feed rated current into a short-circuit. Fuses would not blow, over-current relays would not pick up. Of course, the system voltage would be low, but distribution system protection is not often based on voltage or impedance information.

This means that if a fault occurs, and the fuses blow between the fault and the incoming power system, a DSG might succeed in keeping the distribution system energized at low voltage. This would not harm the DSG, and might result in burning the fault clear, but most utilities would avoid this condition because of possible damage to consumer equipment. For some DSGs a version of the network protector used in urban grid distribution systems might be suitable. For others, new relaying methods might have to be devised.

Clearly, the subject of system/DSG protection coordination is worthy of further study, whether or not the DSG can provide enough fault current to blow fuses. Among the possible situations which might arise under fault conditions is islanding.

When a fault occurs on a power system, the protection system operates so as to isolate and de-energize the fault. In the bulk system, because of the high degree of interconnection needed to achieve suitable reliability, at least two breakers will operate. There are always two or more possible infeeds to any point on the bulk system. On the distribution system interconnection is rare as the system is usually operated radially. This means that only one breaker or fuse need operate to isolate a fault.

With DSG installed, some locations on the distribution system might have two possible infeeds even without interconnection. If the utility protection system is left unaltered, a situation could arise where a DSG is left supplying a portion of the local distribution system; a kind of power system in miniature.

While such operation may be technically feasible, it seems likely that only the largest, utility-owned DSGs would be permitted to continue operation as an island. There are two reasons for this. First, small DSGs can only feed small loads. Small loads are unlikely to contain enough diversity for successful, stable operation, so that frequency and voltage control would be poor. Few utilities would permit such a state of affairs. Not all DSGs are suitable for independent operation, in any case. To operate as a miniature power system, the generator must be controllable, predictable and have voltage control capability. According to Table 2-1, wind, photovoltaics and solar thermal fail to qualify as candidates for islanded operation because of the unpredictable nature of their resource.

There is a second reason why islanding may not be practical. If the DSG were large and suitably controllable, but not utility owned, the liability in the event of problems caused by the DSG operating islanded and under utility control may be complex.

I. NON REAL-TIME IMPACTS

Most of this report is concerned with real-time control aspects of DSG. Clearly, the integration of DSG into the distribution system will impact planning, maintenance and design aspects of the system too.

A number of long-term impacts of DSG integration may be identified. Some of the more important institutional and economic factors are discussed in a JPL report [Reference 8]. Only the technical factors will be considered here.

1. Standardization

If DSG is to make a significant contribution to the nation's energy needs, it is likely that the addition of small DSGs to the system cannot continue to be handled on a case-by-case basis by the utilities. This means that a much greater degree of standardization is called for, especially from the small, residential sized units. Interface standardization is an area worthy of much attention, perhaps modelled after the IEEE 488-bus (GP-IB). What is really required would include standardization of the physical connections, of the voltage levels and meaning of each connection, and quality standards for the various signals including the AC power itself. The protection system should also be standardized, although not necessarily identical for all DSGs. Perhaps interface standards could be defined for ranges of size of DSGs. Once this is done, DSG manufacturers can obtain type-approval for the device, based on its satisfying the interface requirements. The utility or the local authority could then approve the DSG for connection through an inspector rather than an engineer.

2. Ownership

Institutional aspects of DSG integration include resolution of the legal problems of consumer ownership of utility connected generation, and settlement of the question of buy-back rates. There are also technical questions of maintenance and environmental impact which may have to be faced by both the DSG owner and the utility.

3. Management Changes

The effort required from the utility in approving DSG interconnection, in settling questions of rates and maintenance, and in participating in zoning and environmental hearings on the scale indicated by the expected growth of DSG, may call for the creation of special groups within the utility. This would especially be true towards the end of the century when the number of DSGs being installed is expected to rise rapidly.

Planning for distribution system expansion or reinforcement might be facilitated by the use of the substation controller. Three quarters of the load growth on a distribtuion system now occurs in ways which do not require the utility be notified. Planning is, therefore, largely a matter of estimating future load growth. The accuracy of the estimate of load growth would be improved if data were available to more accurately indicate trends. Such data could be obtained by an intelligent acquisition/storage system installed as part of the substation controller system.

4. Billing Meter

Historically, energy flowed only in one direction through the Watt-hour meter, whose reading therefore increased monotonically. A DSG on the customer's side of the meter might cause the meter to run in reverse, essentially selling electricity back to the utility at retail price. Since the DSG owner is not providing the services of frequency control, voltage control or spinning reserve, and is selling electricity when he has surplus rather than on demand, and since he may not have some of the utility's expenses (such as the provision of a meter and a reading and billing service) most utilities would regard this as unreasonable. A variety of alternatives exist. The particular choice will probably become standardized with the type and size of DSG.

J. SUMMARY

(1) Diagrams Are Useful for Studying Control Requirements

Functions can be summarized in diagrams, which in turn demonstrate the hierarchy of the system. Additionally, the operational interfaces can be expressed and the communications requirements may then be derived. The set of diagrams must be made to match each other, which results in a comprehensive base for the design process. The net gain is a clearer picture of a total design, an opportunity to evaluate alternative hierarchical structures and ensure that all required functions are correctly allocated at the proper control points.

(2) Distribution Systems Are Not Uniform

There is a great variety of distribution systems around the world, but they may typically be arranged to show parallelism between control and power system. Thus, there generally exists a hierarchy, in which two or more control levels are logically required. Location of control levels is a function of both requirements and existing capabilities. For DSG control, a logical intermediate level occurs at distribution substations.

(3) Functions of Distribution Substation Controller

In the case of DSGs, there is an expanded communication and control role for the lower part of the overall system. For example, at a distribution substation controller, typical functions include the translation of commands for local implementation, monitoring and alarm generation and notification, data storage capability, as well as local or centralized control as appropriate.

(4) Functions of DSG Controller

At a DSG controller, the functions of command translation for the generic DSG type including startup and shutdown, monitoring and alarm generation, data storage, data transfer, and local display of the status of the plant, are typical functions to be implemented.

(5) Protection

Protection impacts center on the possibility of multiple infeed and non-linear control parameters. Overcurrent protection devices are not necessarily applicable; faults might result in low voltage with consequent customer equipment damage. New devices like network protectors need to be developed.

(6) Islanding

Small DSG units cannot be used to support isolated loads because there is insufficient diversity. Even suitably controlled larger DSGs can lead to operational and legal problems not previously experienced.

SECTION V
CONCLUSIONS AND RECOMMENDATIONS

A. CONCLUSIONS

It was found convenient in this study of the impact of DSG upon energy management systems to examine the impacts in two geographically different areas: the control center and the remainder of the system. Once the impacts in these areas are understood, it is possible to synthesize an energy management system that can handle DSG in an integrated fashion.

As far as the energy control center is concerned, it was assumed that the basic objectives and activities would remain unchanged as DSGs were added to the power system. Although the DSGs are in the distribution system, and not normally directly addressable from the ECC, it is to be considered essential that the operation of the larger DSGs be coordinated with other generation in the system. It is also desirable to coordinate the smaller DSGs in a similar manner.

As far as the control of real power is concerned:

(1) Broadly speaking, the operation of DSGs in the distribution system does not seem inconsistent with the objectives or functions of the energy management system. In order to integrate the operation of DSGs, some changes are required in the programs executed routinely at the control center, and some hardware changes are indicated outside the center.

(2) Because some DSGs rely on primary energy sources that are not predictable, their integration into the power system could result in increased activity on the part of generation used in the regulator mode. There is an economic penalty associated with such increased activity. It may be possible to reduce the effect of DSG on regulating central generators by having other DSGs, primarily those whose regulators use no moving parts, assume some of the regulating duty.

(3) A high penetration of DSGs could give an added degree of flexibility to system control. Besides assuming some of the regulator duty, DSGs that are, by definition, dispersed throughout the system could help control loading on individual lines if necessary.

(4) The large number of DSGs required to achieve high penetration calls for simplification of the economic dispatch calculation. One such method has been presented in Section III.

(5) There is a possibility that a DSG operating in the distribution system could become islanded, or separated from the remainder of the utility system. This is possible largely because the distribution system is generally operated radially, so that alternate power infeeds do not exist. Continuous islanded operation is only possible if the island is large enough to mask the effect of individual load changes and if the DSG relies on a predictable controllable source and is under utility ownership and control. The idea of using DSGs to improve the reliability of service is generally not tenable.

DSGs in general provide an additional flexibility in the control of system voltage or reactive power. In particular:

(1) Some means of automatic voltage or VAr control is essential on DSGs, since the voltage at the point of interconnection cannot be assumed constant, and the lack of such capability could result in an unacceptable power factor situation. Power factor control is much more critical with a DSG than with a load of similar rating since, as far as the system is concerned, the real power delivered could be reduced but the reactive power would be increased by the presence of the DSG.

(2) DSG voltage control may provide a method of local voltage regulation to complement existing methods or it could help the system operator control (usually minimize) VAr flow on the system, provided suitable communications and control hardware existed.

(3) Some DSGs can be operated as reactors to consume VArs even when the real power produced is zero. Such a possibility must have economic benefits, especially if the operation is directed from the energy control center.

Since the functions of the ECC remain unaffected by the addition of DSGs, its hardware is not expected to change significantly. It should be a fairly straightforward matter to perform the extra I/O required for DSG control, especially if intelligent controllers are used in a control hierarchy.

One such scheme is examined in Section IV. Here it is seen that:

(1) Diagrams can be used to show functional requirements and define interfaces for a control system hierarchy. There seems to be no limit imposed by this method that makes it not applicable to utility system controls.

(2) A minimum control hierarchy consists of two control levels. There is merit in using three; the added controller being located at the distribution substation. The substation controller can reduce the upgoing data stream to

prevent the control center being overloaded with details, and it could act upon downcoming commands according to a pre-programmed priority. Such techniques would ease the burden at the control center while at the same time providing the required operational flexibility. A substation data system could also provide data for improved local load forecasts.

(3) The protection system operates independently of the control hierarchy discussed above. In order for DSG protection to be properly coordinated with distribution system protection, some new protection ideas may be needed. This arises largely because DSGs and their control systems do not necessarily behave in the same way as conventional generators when subject to faults.

(4) For some DSGs, it may be possible to use versions of the network protectors used in networked urban distribution systems. Network protectors represent developed technology.

B. RECOMMENDATIONS FOR FURTHER WORK

It may be expected that a study of this kind would produce a number of recommendations for future work. Such is the case. Some of the ideas fit nicely into the plans for the Communication and Control Project for the forthcoming year (1981) and others are clearly outside the scope of the Project.

The following areas are worthy of further study:

(1) The substation controller may be of benefit in the system with or without DSG. A first step, a study of design concepts, is incorporated into the 1981 Project Plan.

(2) The DSG controller should be studied as part of the whole system. A study of design concepts is incorporated into the 1981 Project Plan.

(3) The piecewise linear approximation to the fuel cost curve should be examined from an economic, as well as technical viewpoint. The most popular methods in use today were developed in an analytical era, and seem less than ideal for DSGs. The method proposed here is more suited to digital implementation and may be more accurate than present day schemes.

(4) The incorporation of a significant penetration of DSGs into the system may be more economical if the DSGs are based on weather-related energy, by the inclusion of weather data in the computations made at the energy control center. Work is needed in the area of scheduling (long lead time) and

economic operation (short lead time). There may be economic advantage to using a forecast which is updated frequently.

(5) The technical and economic benefits of using DSG voltage control capability to limit reactive flow or control voltage should be studied further. As far as system operation is concerned, the ability to control DSG excitation may be more desirable than control of real power. It may also be more acceptable to the DSG owner.

(6) The design of the so-called power conditioners that could offer maximum operational flexibility should be studied. The minimum cost power conditioner may not represent the most economical choice when the system benefits of integrated operation are considered.

(7) Protection coordination between DSGs and the power system is obviously an area where much additional work should be done.

(8) In the study reported here, the current practices in energy management, DSG and distribution systems were reviewed. A good deal of variability was observed in all these areas. An area worthy of further work, then, is the standardization of the interface between DSGs and the control system. In view of the different operating practices that exist, the wide spectrum of DSGs and the variation in distribution system design, standardization of these interfaces is far from trivial.

REFERENCES

1. IEEE Power Engineering Society Sixth Biennial Workshop on Real-Time Monitoring and Control of Power Systems, University of Wisconsin, October 1980.

2. General Electric Co., Monitoring and Control Requirement Definition Study for Dispersed Storage and Generation, Prepared for JPL and NYSERDA, DOE/JPL 955456-1 and JPL 9950-419, October 1980.

3. Urban Systems Research and Engineering, Inc. Estimates of the Cost of Renewable Energy Technologies for New York State Final Draft, NYSERDA Contract ER-502-78/79 RDD, July 1979.

4. EPRI Technical Assessment Guide, [illegible]S-1201-SR, Special Report, July 1979.

5. U.S. Army Corps of Engineers, Estimate of National Hydroelectric Power Potential at Existing Dams, Institute for Water Resources, July 1977.

6. Kirchmayer, L. K.. Economic Operation of Power Systems, John Wiley and Sons, New York, 1967.

7. Stevenson, W. D., Elements of Power System Analysis, McGraw-Hill, New York, 1962.

8. Bahrami, K. A., et al, Dispersed Storage and Generation Case Studies, JPL Publication No. 79-98, March 1980.

APPENDIX A

SYSTEM CONTROL CENTERS FOR GENERATION - TRANSMISSION SYSTEMS

(From a contribution by T. E. DyLiacco to the IEEE-PES Sixth Biennial Workshop on Real-time Monitoring and Control of Power Systems, Ref. 1).

TABLE A-1
System Control Centers for Generation-Transmission Systems

In-Service Date	Name of Company	Core Size in Words	Bulk Storage in Megabytes	On-Line Functions In Service
June 1969	Michigan Electric Power Ann Arbor, Michigan	128k	10 000k wds	AGC, EDC, SM
July 1970	Penn-Jersey Maryland (PJM) Interconnection Norristown, Pennsylvania	5000k Bytes	4.7	AGC, EDC, SM
Dec. 1970	Central Electricity Generating Board London, England	96k	2000k wds	SM, OLF, SE
	Regional Centers	512k	6	SM
Oct. 1971	Kyushu Electric Power, Fukuoka, Japan	40k	4000k wds	AGC, EDC, VVC, SM
Nov. 1971	Houston Lighting & Power Houston, Texas	80k	17.5	AGC, EDC, VVC, SM
Mar. 1972	Norwegian Water Resources & Electricity Board Tokke, Norway	24k	128k wds	AGC, EDC SE, OLF
June 1972	New York Power Pool, Albany, New York	3000k	1200	AGC, EDC, SM
Oct. 1972	Tohoku Electric Power, Sendai, Japan	120k	2100k wds	AGC, EDC, SM

Oct. 1972	Electric Power Utility Laufenburg, Laufenburg, Switzerland	76k	17.6	AGC, SM, SE
Dec. 1972	Cleveland Electric Illuminating Cleveland, Ohio	244k	12	AGC, EDC, SM, OLF
Feb. 1973	Kassai Electric Power, Osaka, Japan	80k	64k wds	AGC, EDC, SM, OLF
Feb. 1973	Sacramento Municipal Utility District Sacramento, California	64k	4.4	AGC, EDC, SM, VVC
Mar. 1973	Commonwealth Edison Chicago, Illinois	256k	24	AGC, EDC, SM, OLF
Mar. 1973	Tokyo Electric Power, Tokyo, Japan	128k	6000k wds	AGC, EDC, SM
May 1973	General Public Utilities, Reading, Pennsylvania	128k	12	AGC, EDC, SM
	<u>Member Companies</u>			
	Metropolitan Edison	184k	12	VVC
	Pennsylvania Electric	312k	37	VVC
	Jersey Central	296k	37	VVC
July 1973	Interbrabant Schaerbeek, Belgium	76k	2.5	SM, SE, OLF

July 1973	Electricite de France (EDF) National Control Center, Paris France	56k	2000k wds	AGC, SM, SE, OLF
Regional Control Centers				
	Paris	64k		SM
	Lille	48k	3	SM, OLF
	Nancy	40k	6	SM, OLF
	Lyon	40k	6	SM, OLF
	Marseille	36k	6	SM
	Toulouse	40k	6	SM
	Nantes	48k	3	SM, OLF
Sept. 1973	Southern Services Birmingham, Alabama	8000k Bytes	5200	AGC, EDC, SM, OLF, SE
Oct. 1973	American Electric Power, Canton, Ohio	112k	3	AGC, EDC, SE
Oct. 1973	Philadelphia Electric Philadelphia Pennsylvania	336k	140	AGC, EDC, SM
Nov. 1973	Hokuriku Elec- tric Power Toyama, Japan	56k	3000k wds	AGC, EDC, SM, SE
Mar. 1974	Hong Kong Electric Victoria, Hong Kong	160k	20	AGC, EDC, SM, VVC
April 1974	Sydkraft Malmo, Sweden			EDC, SM
May 1974	Pennsylvania Power & Light Allentown, Pa.	1000k	39	AGC, EDC, SM
Sept. 1974	Carolina Power & Light Raleigh, North Carolina	168k	4.5	AGC, EDC SM

Dec. 1974	Bonneville Power Administration Portland, Oregon	800k	36000k wds	AGC, SM SE
Dec. 1974	Iowa-Illinois Gas & Electric Davenport, Iowa	256k	12 ea.	AGC, EDC, VVC, SM OLF
Jan. 1975	Sierra Pacific Power, Reno, Nevada		2	AGC, EDC SM
April 1975	City of Gainesville, Gainesville, Florida	104k	3	AGC, EDC VVC, SM
June 1975	Public Service Electric & Gas Newark, New Jersey	96k	56000k wds	VVC, SM
Aug. 1975	Wisconsin Electric Power Milwaukee, Wisconsin	428k	400	AGC, EDC, SM, SE, OLF
Aug. 1975	Tennessee Valley Authority Chattanooga, Tennessee	5[illegible]0k	500k wds	AGC, EDC, SM
Oct. 1975	Rheinisch-Westfalisches Elektrizitatswerk (RWE) Brauweiler, West Germany	128k	9000k wds	AGC, SM, OLF
Oct. 1975	Rhode Island-Eastern Massachusetts-Vermont Energy Control Westborough, Mass.	48k	2131k wds	AGC, EDC, SM
Oct. 1975	Pacific Gas & Electric San Francisco, California	340k		VVC

Nov. 1975	Technische Werke der Stadt Stuttgart (TWS) Stuttgart, West Germany	64k	4.8 Mwds	SM, SE, OLF
Dec. 1975	Middle South Services Pine Bluff, Arkansas	164k	24	AGC, EDC, SM, OLF
	<u>Member Companies</u>			
	Arkansas Power & Light	224k	13	VVC
Dec. 1975	Detroit Edison Detroit, Michigan	160k	104	VVC,SM
Dec. 1975	Ontario Hydro Toronto, Canada	1000k	200k wds	AGC,EDC, SM,SE,OLF
1976	National Power Administration Warsaw, Poland	160k	44	AGC,EDC,SM
April 1976	Societe Pour la Coordination de la Production et du Transport de L'energie Electrique National Dispatching Linkebeek, Belgium	200k		SM,VVC
	<u>Regional Dispatching</u>			
	Linkebeek			SM
	Charleroi	80k	2	SM
May 1976	Potomac Electric Power Washington, D.C.	312k	386	VVC
June 1976	Eastern Iowa Light & Power Wilton, Iowa	160k	14.4	AGC,EDC,SM, VVC
Oct. 1976	Arizona Electric	128k	8.8	AGC,EDC,SM

	Power Cooperative Benson, Arizona			VVC
Dec. 1976	Chubu Electric Power, Magoya, Japan	224k	30	AGC,EDC,SM, VVC
Feb. 1977	Swedish State Power Board Stockhom, Sweden	480k	226	SM
April 1977	Board of Public Utilities Kansas City, Kansas	112k	33	AGC,EDC,SM
May 1977	Utah Power & Light Salt Lake City, Utah	192k	212	AGC,EDC,SM, VVC
June 1977	Nova Scotia Power Halifax, Nova Scotia	160k	7.7	AGC,SM,VVC
June 1977	Kansas City Power & Light Kansas City, Missouri	80k	17	AGC,EDC,SM
July 1977	Omaha Public Power District Omaha, Nebraska	256k	12	AGC,EDC,SM
Nov. 1977	Corn Belt Power Co-op Humboult, Iowa	64k	8.8	AGC,EDC,SM
Dec. 1977	Institute de Recursos Hidraulicos y Electrificacion Panama City, Panama	128k	6	AGC,EDC,SM
Dec. 1977	China Light & Power Kowloon, Hong Kong	256k	11.2	AGC,EDC,SM

Early 1978	Fuerzas Electricas de Cataluna (FECSA) Barcelona, Spain	128k	15.5	AGC,EDC,VVC, SM
March 1978	Gas-Elektrizitats-und Wasserwerke (GEW) Cologne, West Germany	256k	8.8 Mwds	EDC,SM,SE,OLF
April 1978	Public Utilities Board, Singapore	128k	7.2	AGC,EDC,SM
June 1978	Jacksonville Electric Authority Jacksonville, Florida	248k	8	AGC,EDC,VVC, SM
Aug. 1978	Public Service of Oklahoma Tulsa, Oklahoma	592k	64	AGC,EDC,SM
Aug. 1978	Minnesota Power & Light, Duluth, Minnesota	256k	23	AGC,EDC,VVC, SM
Mid 1978	Compania Sevillana de Electricidad Madrid, Spain	256k	32	AGC,EDC,VVC, SM,OLF
Mid 1978	Romergo National Load Disptaching Bucharest, Romania	248k	9.6 Mwds	EDC,SM,SE
Sept. 1978	Wisconsin Power & Light Madison, Wisconsin	256k	100	AGC,EDC,SM
Nov. 1978	Dairyland Power Cooperative La Crosse, Wisconsin	88k	126	AGC,EDC,VVC, SM
Late 1978	Hungarian Electric Power Budapest, Hungary	192k	32.8	AGC,EDC,SM, OLF

Jan. 1979	Southern California Edison Los Angeles, California	800k	570	AGC
March 1979	Alabama Electric Cooperative Andalusia, Alabama	128k	6	AGC,EDC,SM
May 1979	El Paso Electric El Paso, Texas	128k	6	AGC,EDC,SM
June 1979	Vereinigte Elektrizitats-werke Westfalen (VEW) Dortmund, West Germany	930k	104 Mwds	AGC,SM
June 1979	Delmarva Power & Light Wilmington, Delaware	352k	50 Mwds	AGC,EDC,SM, SE
Aug. 1979	Servicios Electricos del Gran Buenos Aires (SEGBA) Buenos Aires, Argentina	384k	50	SM,SE,OLF
Aug. 1979	Korea Electric Seoul, Korea	128k	6	AGC,EDC,SM
Sept. 1979	Florida Power & Light Miami, Florida	776k	30 Mwds	AGC,EDC,SM, SE,OLF
Sept. 1979	Hidroelectrica Espanola Madrid, Spain	228k	50	AGC,EDC,SM
Nov. 1979	Virginia Electric & Power Richmond, Virginia	256k	40	AGC,EDC,SM, OLF

Late 1979	Energie-Vesorgung Schwaben (EVS) Wendlingen, West Germany	2000k	248	SM,VVC
Dec. 1979	Hoosier Energy Division Bloomington, Florida	128k	6	AGC,EDC,SM
Feb. 1980	Florida Power St. Petersburg, Florida	496k	66	AGC,EDC,SM, VVC,SE,OLF
April 1980	Taiwan Power Taiipei, Taiwan	192k	40	AGC,EDC,SM, OLF
Early 1980	Energie Electrique de la Cote d'Ivoire Abidjan, Ivory Coast	384k	254	AGC,EDC,SM, SE
May 1980	New England Power Exchange (NEPEX) West Springfield, Mass.	512k	420	AGC,EDC,SM, OLF
June 1980	Cajun Electric New Roads, Louisiana	256k	100	AGC,EDC,SM
July 1980	Portland General Electric Portland, Oregon	384k	50	AGC
Aug. 1980	Central Louisiana Electric St. Landry, Louisiana	512k	60	AGC,EDC,VVC, SM

<u>Key</u>

AGC	Automatic Generation
EDC	Economic Dispatch Control
VVC	Voltage/VAr Control
SE	Static State Estimation
OLF	On-line Load Flow
SM	Security Monitoring

APPENDIX B

ECONOMIC SCHEDULING OF DISPERSED STORAGE AND GENERATION

(A contribution by F.C. Schweppe of M.I.T. to the GE report on the control and monitoring requirements for DSG, Ref. 2).

TABLE OF CONTENTS

1. Introduction

The economic scheduling of distributed storage and generation units (DSG) presents new problems because of the hypothesized large numbers that are geographically dispersed, the stochastic nature of some of them, and the possibility of non-utility ownership. THis report discusses in general terms scheduling issues and techniques.

2. Problem Definition

The basic problem is to schedule real power generation and storage to minimize total fuel costs while meeting the demand subject to constraints on generation reserve, transmission network limitations, and distribution network limitations. The effect of losses is explicitly considered. Voltage var scheduling is not addressed. An extension to be discussed in the last section allows for the rescheduling of customer demand and hence incorporates rescheduling costs into the overall cost.

Real power scheduling is divided into three different time scales:

. Economic Dispatch: Every 5 minutes.

. Unit Commitment: Hour by hour for next week.

. Maintenance Scheduling: Week by week basis for next year.

Three types of DSG units are defined as follows:

. Schedulable by Utility . Schedulable by Customer	Cogeneration, fuel cells, batteries hydro with storage, etc.
. Nonschedulable	Solar, wind, run of river hydro, etc.

It is assumed henceforth that nonschedulable run of river, solar, wind generation will be run at maximum possible levels at all times independent of whether it is owned by the utility or customers. The only exception would be when distribution network limitations are being approached or exceeded.

The discussions consider only the information processing and decision making systems needed to perform the scheduling. Communication links, instrumentation, and actuators are not discussed.

There are several possible levels and types of decomposition of decision making/information processing. Figure 1 shows a three level process involving the Energy Management System (EMS), the Distribution

Dispatch Center (DDC), and the DSG units themselves. Figure 2 shows a four-level decomposition involving the EMS, the DDC, the Distribution Automation Control Center (DAC) and the DSG unit itself. In Figures 1 and 2, the utility is assumed to own the DSG unit. In Figure 3 the DSG unit is assumed to be installed "behind the meter" within the customer's system so the utility has no direct communication with the DSG unit itself.

Only the case of many small DSG units is being considered. If there are very large DSG units on the system, it is assumed they will be scheduled from the central dispatch Energy Management System (EMS) just as regular central power plants and storage units are. Numerical values for the terms "large" and "small" are system dependent.

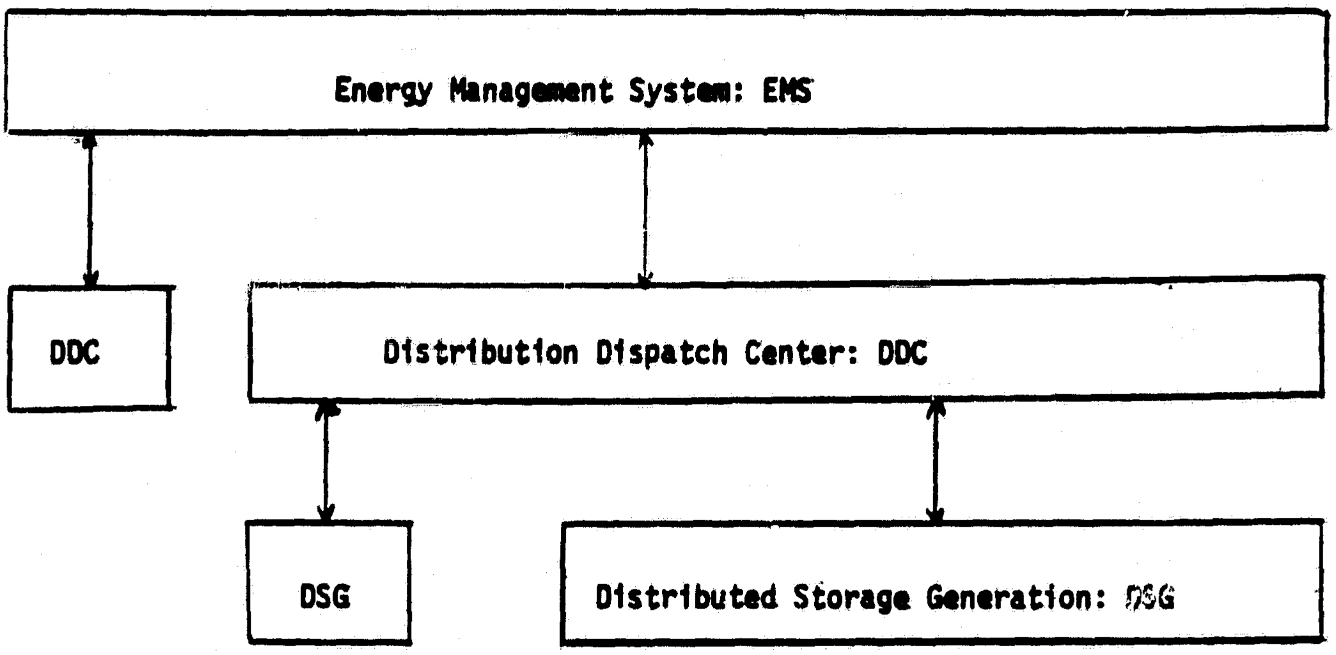


Fig. 1. Three Level Decomposition: Utility owned DSG

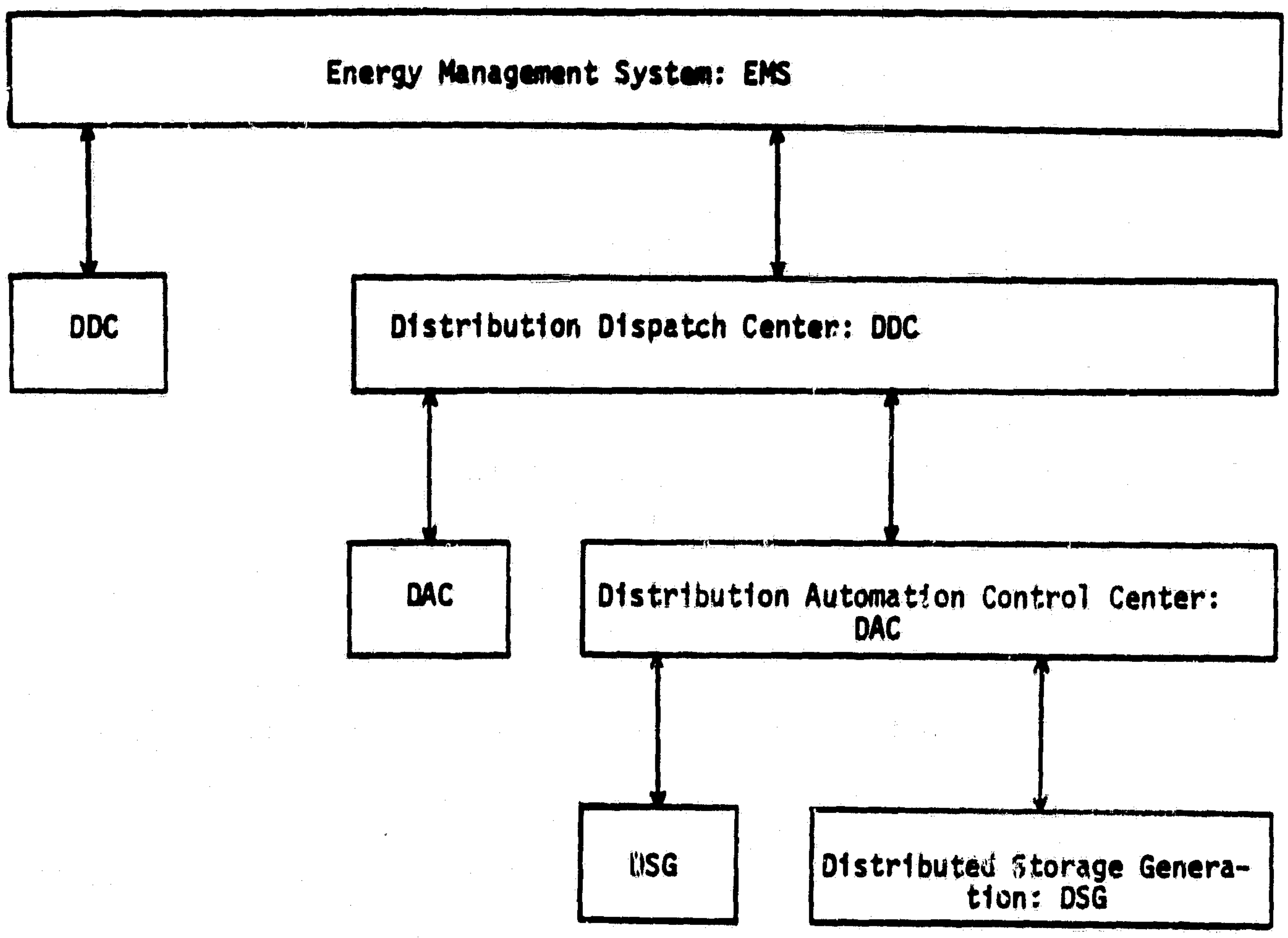


Fig. 2. Four Level Decomposition: Utility owned DSG

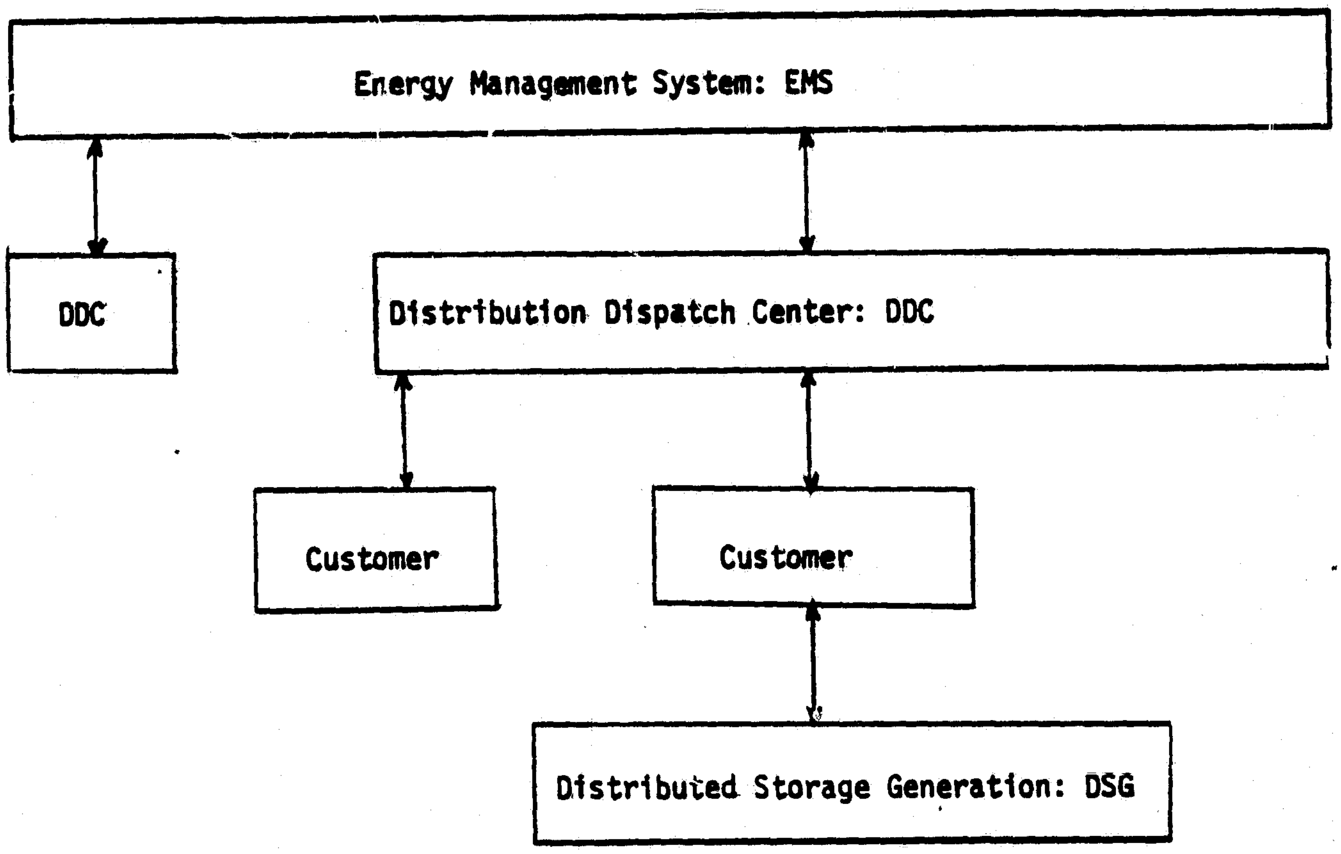


Fig. 3. Three Level Decompostion: Customer Owned DSG

3. Weather

Solar and wind units provide a weather dependent DSG capability. Since the weather is a random process, the units cannot be scheduled in the usual sense.

A highly simplified dichotomy of weather types is:

- Microweather: Five minute local variations in cloud cover, wind speed, etc.
- Macroweather: Passage of overall weather fronts and air masses.

Two key assumptions made in subsequent discussions are:

- Macroweather is the same for all DDC units under a single EMS.
- Random microweather variations are statistically independent between DDCs.

In some of the discussions, the following additional assumption is also used:

- Random microweather variations are independent between DSG units in a single DDC area.

There are various ways these assumptions could be weakened without affecting the overall conclusions. For example, if a particular EMS had several macroweather patterns to worry about, the only change would be an increase in complexity of weather monitoring and modeling. It would not affect the basic principles. Similarly, some degree of statistical dependence between microweather variations between DDCs or within a DDC geographical area would not change the basic conclusions as long as such statistical dependence does not become dominant.

4. Uncertainty

The uncertainties associated with random wind and solar variations, with plant outages, and with the difficulties of accurate economic scheduling can influence the overall design of a scheduling system. The following discussions consider highly simplified models. However, it is felt these models convey basic attributes of the relative effects of a few large central station power plants versus many small DSG plants.

4.1 Random Generation due to Microweather Variations

Consider two types of power plants; central station and dispersed solar or wind. Define:

$$g_{ck} = X_c + \varepsilon_{ck} \qquad k = 1 \ldots N_c$$

g_{ck}: generation output (Kw) of k^{th} central station plant

X_c: average (mean) generation of k^{th} central plant

ε_{ck}: Zero mean random variation of output of k^{th} central plant due to normal plant variation

$$E(\varepsilon_{ck})^2 = \delta_c^{\,2}$$

$\frac{\delta_c}{X_c}$: standardized level of variation in central plant

N_c: number of central plants

Similarly, define:

$$g_{dk} = X_d + \varepsilon_{dk} \qquad k = 1 \ldots N_d$$

g_{dk}: output of k^{th} dispersed plant

X_d: average generation

ε_{dk}: zero mean random variation of output due to micro weather variation in solar or wind

$$E(\varepsilon_{dk})^2 = \delta_d^{\,2}$$

$\frac{\sigma_d}{X_d}$: standardized level of variation

N_d: number of dispersed plants

g: total generation of all plants

so that

$$g = N_c X_c + N_d X_d + \sum_{k=1}^{N_c} \varepsilon_{ck} + \sum_{k=1}^{N_d} \varepsilon_{dk}$$

Finally, assume:

The random variables ε_{ck} and ε_{dk} are statistically independent for all k.

Define:

$\bar{g} = E(g) = N_c X_c + N_d X_d$: expected total generation

$\sigma_g^2 = E\ (g-\bar{g})^2$: variance of total generation

$\rho = \frac{\sigma_g}{\bar{g}}$: standardized level of total variation

It follows from the assumption of statistical independence that:

$$\rho^2 = \frac{N_c \sigma_c^2 + N_d \sigma_d^2}{\bar{g}^2} \tag{4.1}$$

Define:

$$\rho_c^2 = \left(\frac{\sigma_c}{X_c} \right)^2 \frac{X_c}{\bar{g}}$$

and

$$\rho_d^2 = \left(\frac{\sigma_d}{X_d} \right)^2 \frac{X_d}{\bar{g}}$$

where

$\rho_c = \rho$ when $N_d = 0$ (all central)

$\rho_d = \rho$ when $N_c = 0$ (all distributed)

Define

$$\beta = \frac{N_d X_d}{\bar{g}} = \frac{N_d X_d}{N_d X_d + N_c X_c} : \text{"percentage" of distributed generation}$$

so

$$1 - \beta = \frac{N_c X_c}{\bar{g}} : \text{"percentage" of central generation}$$

Then, it follows from (4.1) that:

$$\rho^2 = \rho_c^2 (1-\beta) + \rho_d^2 \beta \qquad (4.2)$$

$$0 \leq \beta \leq 1$$

For the sake of example, assume:

$\bar{g}$ = 10,000 MW	(total average generation)
X_c = 400 MW	(size of central unit)
X_c = 1 MW	(size of dispersed unit)
$\left(\frac{\sigma_c}{X_c} \right) = 0.01$	(1% variation for one central unit)
$\left(\frac{\sigma_d}{X_d} \right) = 0.2$	(20% variation for one dispersed unit)

Then

$$\rho_c = (0.01) \left(\frac{400}{10000}\right)^{1/2} = 0.002$$

$$\rho_d = 0.2 \left(\frac{1}{10000}\right)^{1/2} = 0.002$$

so that

ρ = 0.2%: independent of relative percentage of central and dispersed generation

Obviously for other sets of numbers, Eq. 4.2 does yield a standard level of variation ρ which depends on the mix of dispersed to central. However even for 20% to 50% variation in the individual dispersed units, the resulting percentage variation ρ at the system level is small for most cases of concern, independent of number of dispersed units.

The key overall conclusion is that

"Effect of stochastic local variations in microweather patterns on small solar and wind units can be ignored at EMS level, independent of number of units".

The key assumption underlying this conclusion is the statistical independence of the microweather variations over the geographical area covered by the EMS.

4.2 Random Generation Due to Macroweather Variations

Consider the situation discussed in Section 4.1 except that the definition of ε_{dk} is changed to

ε_{dk}: zero mean random variation of output due to macroweather variations in solar or wind

Then instead of the ε_{dk} k = 1... being statistically independent as with microweather, they are all equal with macroweather; i.e.,

$$\varepsilon_{dk} = \varepsilon_d \qquad k = 1 \ldots N_d$$

In this case (4.1) becomes

$$\rho^2 = \frac{N_c\,\sigma_c^2 + N_d^2\,\sigma_d^2}{\bar{g}^2} \tag{4.3}$$

and (4.2) becomes

$$\rho^2 = \rho_c^2\,(1-\beta) + N_d\,\rho_d^2\,\beta \tag{4.4}$$

The factor N_d in (4.4) is not in (4.2) and completely changes the conclusions.

Consider the numerical example of Section 4.1. Using (4.4) instead of (4.2) yields

$$\rho^2 = (0.002)^2\,(1-\beta + N_d\beta)$$

If

$$N_d = 2000 \qquad N_c = 20$$

then

$$\beta = .2$$

$$\rho \approx (0.002)\,(400)^{1/2} = .04 = 4\%$$

If

$$N_d = 4000 \qquad N_c = 15$$

then

$$\beta = .4$$

$$\rho \simeq 8\%$$

Uncertainties of this size cannot be ignored by the EMS.

The key overall conclusion is that

"Effect of global variation in macroweather patterns on solar wind units is very important at EMS level unless the number of units is small".

The reason for the difference between microweather and macroweather conclusions lies in the different effects of independent and dependent statistical variations.

4.3 Plant Outages

Consider two types of plants; central station and dispersed. Define:

$g_{ck} = X_c \delta_{ck} \qquad k = 1 \ldots N_c$

$g_k = X_d \delta_{dk} \qquad k = 1 \ldots N_d$

g_{ck}, g_k : maximum available generation of k^{th} plant

X_c, X_d: installed capacity of plant

δ_{ck}, δ_{dk}: forced outage process of k^{th} plant

$$\delta_{ck} = \begin{cases} 1 & \text{probability } p_c \\ 0 & \text{probability } 1 - p_c \end{cases}$$

$$\delta_{dk} = \begin{cases} 1 & \text{probability } p_d \\ 0 & \text{probability } 1 - p_d \end{cases}$$

$g = \sum g_{ck} + \sum g_{dk}$: total available capacity

$\overline{g} = E(g) = N_c X_c p_c + N_d X_d p_d$: average available capacity

$\sigma_g^2 = E\{(g-\overline{g})^2\}$: variation of available capacity

$$\rho = \frac{\sigma_g}{\bar{g}}$$

If the δ_{ck} and δ_{dk} are all independent random variables, it follows that

$$\rho^2 = \frac{N_c X_c^2 p_c(1-p_c) + N_d X_d^2 p_d(1-p_d)}{\bar{g}^{\,2}} \tag{4.5}$$

Define:

$$\rho_c^2 = (1-p_c)\,\frac{X_c}{\bar{g}}$$

$$\rho_d^2 = (1-p_d)\,\frac{X_d}{\bar{g}}$$

$$\beta = \frac{N_d X_d p_d}{\bar{g}}.$$

$$1 - \beta = \frac{N_c X_c p_c}{\bar{g}}$$

so (4.5) becomes

$$\rho^2 = \rho_c^2(1-\beta) + \rho_d^2\beta \tag{4.6}$$

$$0 \leq \beta \leq 1$$

Equation (4.5) "looks like" Equation (4.2), but the definition of ρ_c, ρ_d and β are different as (4.2) is for a continuous random variation ε while (4.4) is for an "on/off" binary random cutages δ. However, the general conclusions are similar. For example, consider a system with:

X_c = 400 MW

X_d = 1 MW

p_c = 0.95

$$p_d = 0.5$$
$$N_c = 20$$
$$N_d = 2{,}000$$
$$\bar{g} \approx 9{,}000 \text{ MW}$$

Then

$$\beta = .12$$
$$\rho_c = 5(10^{-2}) \approx 5\%$$
$$\rho_d = .75(10^{-2}) \approx .75\%$$
$$\rho \approx 5\%$$

which means most of the variation is caused by the centeral power plants not the distributed ones.

The key overall conclusion is that

"Effect of random outages of many small dispersed units can be ignored at EMS level".

Once again the key assumption leading to this conclusion is that outages are statistical independent processes.

4.4 Economic Scheduling Errors

Consider a single dispatchable, fuel burning dispersed plant. Define

λ : "system lambda," incremental fuel cost at the EMS level; i.e. for overall system (\$/kWH).

λ_d: incremental fuel cost for single dispersed plant (\$/kWH)

Assume the dispersed plant is small enough so that its scheduling does not effect the system λ. Assume λ_d can be considered to be constant for all levels of dispersed plant output. Assume all lambda's are corrected for

transmission-distribution losses if important.

The optimum scheduling logic for the dispersed plant is then

$$\begin{aligned} &\text{when } \Delta\lambda > 0, \text{ dispersed plant is on} \\ &\text{when } \Delta\lambda < 0, \text{ dispersed plant is off} \\ &\Delta\lambda = \lambda - \lambda_d \end{aligned} \tag{4.7}$$

Define a random variable δ by

$$\delta = \begin{cases} 1 & \text{when schedule error is made} \\ 0 & \text{when schedule error is not made} \end{cases}$$

or

	Plant On	Plant Off
$\Delta\lambda > 0$	$\delta = 0$	$\delta = 1$
$\Delta\lambda < 0$	$\delta = 1$	$\delta = 0$

Define

c : cost of scheduling error (\$/kWH)

$c = |\Delta\lambda|\ \delta = |\lambda-\lambda_d|\delta$

$p(\lambda)$: probability density of λ

$p(\delta=1/\Delta\lambda)$: probability $\delta = 1$ given a particular value for $\Delta\lambda = \lambda-\lambda_d$

Then

$E\{c\}$ = expected (average) cost of scheduling error (\$/kWH)

$$E\{c\} = \int |\Delta\lambda|\ p(\lambda)\ p(\delta=1/\Delta\lambda)d\lambda \tag{4.8}$$

Various reasonable forms for $p(\lambda)$ and $p(\delta=1/\Delta\lambda)$ could be hypothesized. Two are illustrated in Figure 4. The system λ is simply assumed to be uniformly distributed between λ_{max} and λ_{min}. Relative to the scheduling errors the parameter σ plays a key role as

σ = measure of error in scheduling, i.e. σ small implies accurate scheduling

Using the form of Figure 4 (4.8) becomes (assuming $\lambda_{max} > \lambda_d \pm \sigma > \lambda_{min}$)

$$E\{c\} = \frac{\sigma^2}{6(\lambda_{max}-\lambda_{min})} \quad (\$/kWH) \tag{4.9}$$

Equation (4.9) gives the expected scheduling cost per kWH. In order to translate into yearly costs, define

X_d: capacity of dispersed plant (MW)

h_d: number hours run per year (hours)

C_τ: total cost per year of scheduling errors ($/year)

Then

$$E\{C_\tau\} = \frac{X_d h_d \sigma^2}{6(\lambda_{max}-\lambda_{min})} \quad (\$/year) \tag{4.10}$$

For a numerical example, consider

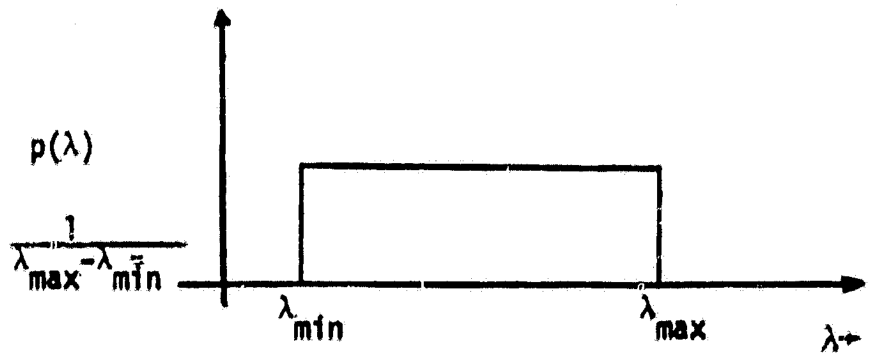
σ = 5 mills/kWH

$\lambda_{max}-\lambda_{min}$ = 50 mills/kWH

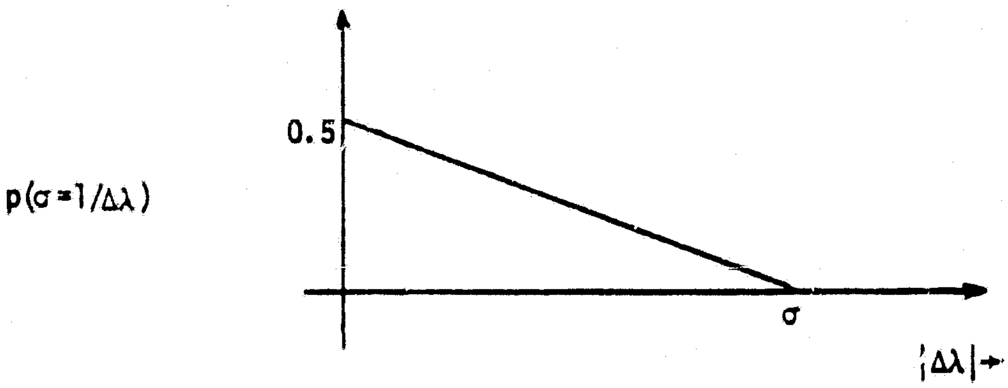
h_d = 6000 hours

so (4.10) yields

$$E\{C_\tau\} = 500\ X_d \quad (\$/year)$$



$p(\lambda)$: probability density of λ



$p(\sigma=1/\Delta\lambda)$: probability of scheduling error for given value of

$\Delta\lambda = \lambda - \lambda_d$

$$p(\sigma=1/\Delta\lambda) = (1 - \frac{|\Delta\lambda|}{\sigma})\ (0.5)$$

Fig. 4

For a one MW plant,

$$E\{C_T\} = \$500/\text{year}$$

Equation (4.10) can be used in various ways. For example, it provides a method to estimate the value of improving scheduling accuracy which can be used in a cost benefit analysis to determine whether extra communication-computation effort is justified. In the numerical example, it would not be worthwhile to try to improve scheduling accuracy beyond $\sigma = 5$ mills/kWH unless such improvement costs less than \$500 per year.

The discussions have considered only fueled-dispersed power plants. Storage plants such as batteries or small hydro units with pond storage follow in a similar fashion except that the optimum logic of Eq. (4.7) is changed to have the maximum discharge rate when lambda is high and maximum charge rate when lambda is low.

The key overall conclusion drawn from Eq. 4.10 is that

- Highly accurate scheduling is not required/justified for small dispersed units.

The key assumptions underlying this conclusion are

- A wide distribution in system lambda so the optimum scheduling is "obvious most of the time".
- A small DSG unit so the amount of energy involved is not large.

4.5 Discussion of Uncertainty

Four general conclusions made in the preceding section were:

- Uncertainties in DSG generation due to microweather random variations are not important at EMS level.

- Uncertainties in DSG generation due to macroweather random variations can be important at EMS level.
- Random DSG outages are not important at the EMS level.
- Accurate DSG scheduling at EMS level is not required/justified.

These conclusions are based on limited analysis using simplified models. Many details of the analysis are subject to question and criticism. However, it is felt that the general concepts and conclusions are valid. Subsequent discussions make use of these conclusions.

5. Decomposition Principles

Consider Figures 1, 2 and 3 of Section 2. The boxes represent different levels at which information processing-decision making occurs while the lines represent information-data flows. Figure 5 is an abstract version of the same type of decomposition into just two levels: central and local. Some basic principles of decomposition will be discussed in terms of the abstract Figure 5.

Figure 6 summarizes the overall logic flow associated with decomposed information processing and decision making. The cycle from measurement to commands is continually repeated at time intervals appropriate to the particular decision being made (i.e., economic dispatch, unit commitment, or maintenance scheduling).

For the purpose of subsequent discussions, define a model to be

- Model: Set of equations and numerical values which provide estimates of present values and allows prediction of future values of demand (kW), generation costs ($/kWH), generation availability (kW) and weather.

Thus the single term "model" actually encompasses many individual models. Three types of models encountered in the decomposition discussions are:

- Detailed Local Model: Contains all details of local systems.
- Aggregated Local Model: Simplified, aggregated version of the Detailed Local Model.
- Aggregated Global Model: Combination of all Aggregated Local Models into one overall global model.

Figure 7 summarizes the basic ideas underlying two general types of scheduling decomposition

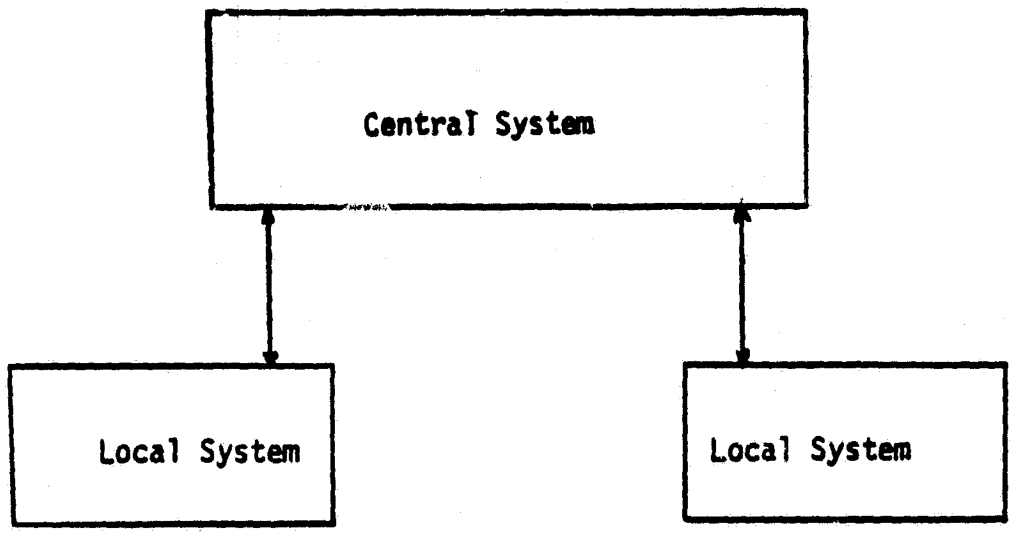


Fig. 5. Abstract Two Level Decomposition.

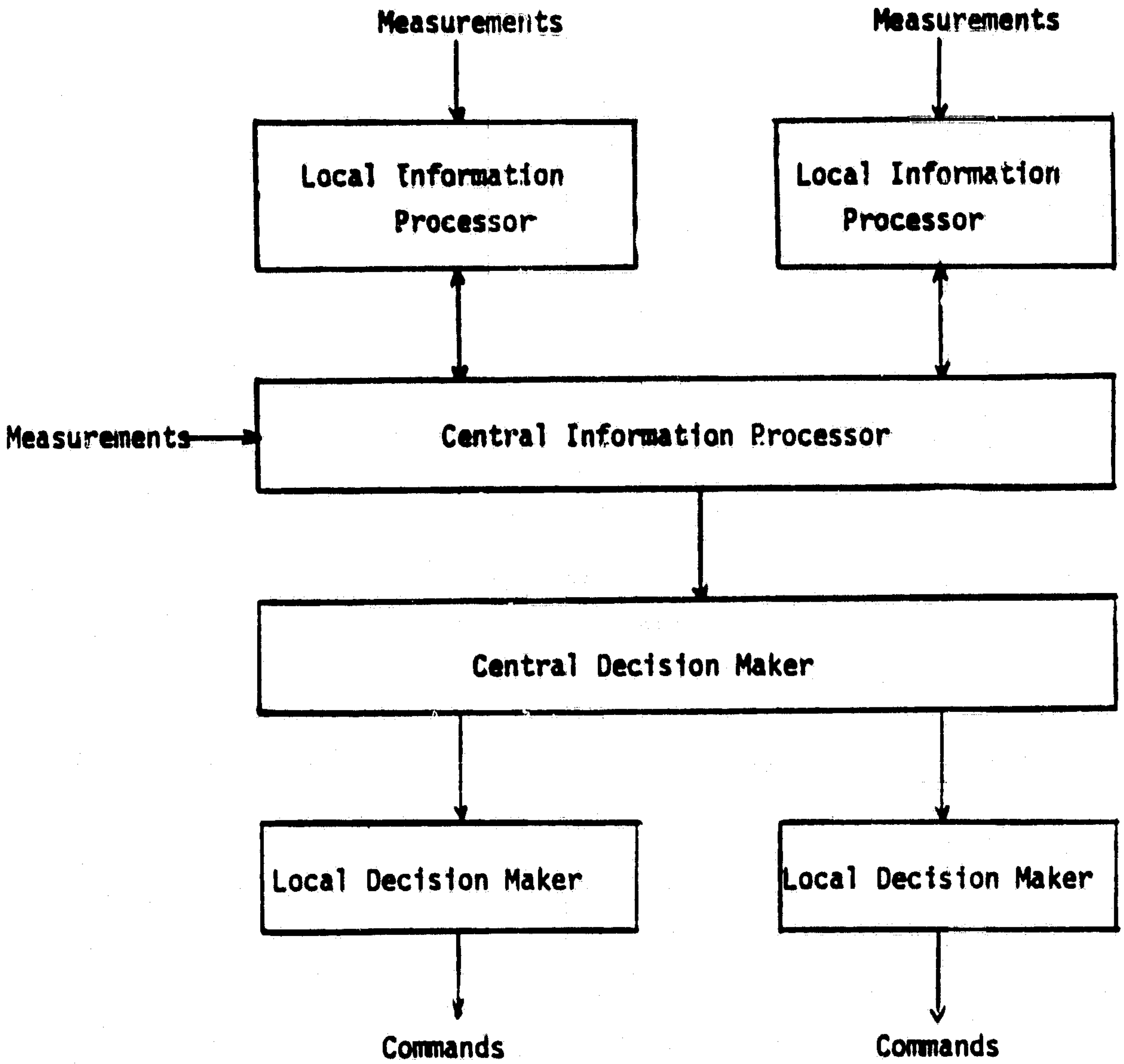


Fig. 6. Overall Logic Flow.

. Quantity Directed Decomposition

. Price Directed Decomposition

As seen in Figure 7 the local and central Information Processor tasks and one of the central Decision Maker tasks are the same under both types of decomposition. With Quantity Directed Decomposition, the central Decision Maker uses the global optimization (done with the Aggregated Global Model) to compute generation level goals called quantity targets (in kW or kWH). The local Decision Makers then use the Local Detailed Models to schedule generation to meet these quantity targets. With Price Directed Decomposition, the central Decision Maker uses the global optimization results to compute price curves ($/kWH vs. kW) for the value of local generation to the overall system. The local Decision Makers then optimize their own performance using Local Detailed Models by trading off the actual local fuel costs against the effective price curves.

In an ideal world with no uncertainty and where the aggregated models are as accurate as the detailed models, the Quantity Directed and Price Directed decompositions yield exactly the same result, i.e., the global optimum schedule. However, in the real world neither will achieve optimality. The best approach depends on many factors and is not a priori obvious in all cases. Furthermore, it is possible to combine the two types of decompositions in various ways. The author of this memo personally prefers Price Directed decomposition because it intuitively "feels better and more natural" for the DSG application problems of concern. Hence, subsequent discussions may show a Price Directed decomposition bias. However all of the important concepts to follow can be applied to either a Price Directed or Quantity Directed decomposition.

<table>
<tr><th></th><th>Quantity Directed</th><th>Price Directed</th></tr>
<tr><td>Local Information Processor Tasks</td><td colspan="2">. Update Detailed Local Models
. Develop Aggregated Local Models</td></tr>
<tr><td>Local to Central Communication</td><td colspan="2">. Aggregated Local Models</td></tr>
<tr><td>Central to Local Communication</td><td colspan="2">. Certain Global Models</td></tr>
<tr><td>Central Information Processor Tasks</td><td colspan="2">. Combine all Aggregated Local Models into Global Aggregated Model</td></tr>
<tr><td rowspan="2">Central Decision Maker Tasks</td><td colspan="2">. Use Global Aggregated Model to compute optimum schedule</td></tr>
<tr><td>. Compute local generator quantity targets</td><td>. Compute local price curves</td></tr>
<tr><td>Central to Local Communication</td><td>. Quantity Targets (kW or kWH)</td><td>. Price Curves ($/kWH or kW)</td></tr>
<tr><td>Local Decision Maker Tasks</td><td>. Use Detailed Local Models to meet Quantity Targets</td><td>. Use Detailed Local Models to minimize local cost given price curves</td></tr>
</table>

Fig. 7. Two General Types of Decomposition

For most cases of concern, it presently appears that the price curves sent out by the central Decision Makers to the local Decision Makers under Price Directed decomposition can be represented by a straight line. Thus the price curves are specified by a nominal generation level in kW and a slope in $/kWH per kW. The nominal kW value "looks like" the target value that would be provided by a Quantity Directed decomposition. There is however a basic difference. In a Quantity Directed decomposition the local Decision Maker tries to hit the kW target. In a Price Directed decomposition, the local Decision Maker tries to minimize costs and the nominal kW simply provides a reference point for the cost curves.

6. Three-Level Decomposition: Utility Owned DSG

Figure 1 of Section 2 shows a three-level decomposition into an Energy Management System (EMS), a Distribution Dispatch Center (DDC), and the Distributed Storage and Generation (DSG) units themselves. The background discussions of Sections 3, 4 and 5 are now applied to this three-level decomposition.

The abstract structure of Figure 5 is applied twice to the specific structure of Figure 1. In other words, the EMS and DDC relationship is viewed as "central to local" relationship as in Figure 5. Similarly, the DDC and DSG relationship is viewed as "central to local" as in Figure 5.

The decomposition discussions of Section 5 apply equally to all three scheduling time scales of concern: economic dispatch, unit commitment, and maintenance scheduling. Obviously the models of concern in the different cases are different. For example, for economic dispatch the various models indicated in Section 5 enable the prediction of future generation, load, weather, etc., on a time span of 5 minutes while for maintenance scheduling, the models enable predictions of costs, availability, etc., on a daily/weekly basis for a year. For the longer time scales such as maintenance scheduling, the actual data processing and communication done between the EMS, DDC and DSG levels is not necessarily done by automatic communication and the information processing and decision making tasks may not involve the use of digital computers. The whole process might be done by committees aided by off-line computer analysis. This, however, does not affect the basic validity of the decomposition concepts discussed in Section 5.

The detailed discussions to follow start with consideration of the various types of "models" that are of prime concern to the various information processors. Then the decision maker tasks are considered.

6.1 Weather Models

In Section 3, a dichotomy of weather types into microweather and macroweather was made. Microweather is 5 minute, local variations in cloud cover, wind speed, etc., while macroweather is the passage of overall weather fronts and air masses. One of the components of the overall model discussed in Section 5 is the weather model which contains both microweather and macroweather models.

The DDC Information Processor may maintain a detailed microweather model for its own region. If so, it updates the microweather model using information obtained and measured locally. It receives the information on a macroweather model from the EMS Information Processor.

The EMS Information Processor maintains and updates the macroweather model for the whole EMS region. The EMS Information Processor is not concerned with the microweather models and no direct information on the microweather models is sent by the DDCs to the EMS. The weather information sent from DDCs to the EMS is information that the EMS needs in order to maintain and update its macroweather model.

Usually the DSG Information Processor is not concerned with weather. If necessary it receives microweather model information from the DDC Information Processor. Weather measurements made at the DSG may be sent directly to the DDC.

6.2 Effective Demand

Solar and wind generation are stochastic processes that depend on the weather. The load/demand are stochastic processes that depend on the weather. The analyses of Section 4.1 indicate that the effects of microweather stochastic variations on solar and wind generation is not a major concern at the EMS level.

The DDC defines a quantity called "effective demand" where

Effective Demand = (Actual Demand) - (Solar Generation)
- (Wind Generation) - (Run of River Generation)

The DDC Information Processor uses historical observations on both effective demand and weather to develop and maintain a statistically based model (time series, fourier series, weather dependent type) for the effective demand. The effective demand model has time and weather as exogenous inputs.

A detailed version of this effective demand model is maintained at each DDC for the use of its own Decision Maker. Either this detailed model itself or a simplified version is sent to the EMS Information Processor to be combined into a global effective demand model covering all DDCs. The individual DDC effective demand models include distribution losses implicitly. If distribution losses are of particular importance to the DDC Decision Maker, a single DDC maintains separate effective demand statistical models for different portions of the distribution system.

The DSG Information Processors are not involved in this modeling except to provide generation data to the DDC.

6.3 Schedulable Generation Models

Schedulable DSG units include fuel cells, batteries, hydro units with storage, and cogeneration.

The DSG Information Processor maintains a very detailed model for the DSG costs and availability. This model or a simplified version of it is sent to the DDC Information Processor.

The DDC Information Processor maintains either the detailed or simplified generation cost, availability models for all of the schedulable generators under the DDC. At the present time it is not clear how accurate these

individual models should be. The analyses of Section 4.4 show that such decisions depend on the relative size of the units, the distribution of system lambda, and other factors. The analyses of Section 4.4 provide formulae and methodology which can be used to provide a rough estimate of the desired accuracy of these individual schedulable generation models maintained at the DDC.

An aggregated schedulable generation model is developed by the DDC Information Processor and sent to the EMS. It consists of a single equivalent generator with nonlinear operating and availability characteristics. This generator includes the effect of distribution losses within the DDC area in an approximate fashion. This approximate equivalent generator may be the result of aggregation around a nominal operating characteristic which the DDC Information Processor feels will be close to the final schedule.

The EMS Information Processor takes the equivalent schedulable generation models from the individual DDCs and combines them into a total overall model including the effect of transmission losses.

The preceding has implicitly been considering fuel type schedulable generation such as fuel cells and cogeneration. In the case of storage devices such as batteries or small hydro with some pond storage capabilities, the same basic philosophies will be followed. The DDC Information Processor turns the individual plant storage capabilities into one equivalent plant model which is then sent to the EMS.

6.4 Transmission Distribution Limitations

Capacity limitations of the transmission distribution systems effect scheduling.

The DDC Information Processors are responsible for maintaining the integrity of their distribution system by insuring that line, transformer, etc. overloads are not occurring and are not predicted to occur under

rational future contingencies. This distribution system model is not explicitly passed to the EMS Information Processor. The effect of distribution limitations are incorporated in the equivalent schedulable generator that is sent to the EMS Information Processor.

The EMS Information Processor has its own information sources on the situation of the transmission network. Limitations on the transmission network capabilities are not sent explicitly to the DDCs. Any such restriction shows up in terms of either the effective price curves or quantity targets provided by the EMS Decision Maker.

6.5 Generation Reserves

Economic scheduling tries to minimize costs while maintaining a satisfactory generation reserve.

Specification of system level generation reserves is the sole responsibility of the EMS Information Processors and Decision Makers. These reserves are then allocated to either central station plants or the various DDCs as appropriate to minimize cost while providing the response capability needed in case of emergencies. The EMS does not worry about microweather stochastic variations of the wind and solar DSG or about the random DSG outages. The EMS Information Processor and Decision Maker do worry about the effect of macroweather on both the load and solar wind generation relative to determining reserves at the unit commitment time scale.

The EMS Decision Maker can assign reserve requirements only to DDCs to carry on schedulable DSG units. This could be done in a straightforward fashion following present day practice by simply assigning each DDC a certain level of reserve to maintain which is then factored into the DDC Decision Maker scheduling logic. This works with either Quantity Directed or Price Directed decomposition. An alternate approach with Price Directed

decomposition is to provide each DDC with a "reserve price curve" so that each DDC individually optimizes its own reserve level relative to the value of such reserve to the overall EMS system.

6.6 EMS Decision Maker

The EMS Decision Maker uses the global aggregated models to determine an optimum schedule (optimizes assuming the global aggregated model is exact). Economic dispatch and maintenance scheduling are done using the same types of algorithms and techniques used today. Unit commitment is done either using the same types of algorithms and techniques used today or using "stochastic decision making".

Stochastic decision making for unit commitment is required only if

- There is a large penetration of wind and solar DSG
- There is a large uncertainty in the macroweather model's predictions of future macroweather

Under these conditions it could be necessary to explicitly factor the uncertainty into the decision making logic for unit commitment; i.e. stochastic unit commitment.

The EMS Decision Maker uses the optimum solution to compute either Quantity Targets or Price Curves which are sent to the DDC Decision Makers.

6.7 DDC Decision Maker

In the case of Quantity Directed decompositions, the DDC Decision Maker uses local detailed models to compute optimum (minimum cost) schedules which met the Quantity Targets provided from the EMS Decision Maker.

In the case of Price Directed Decomposition, the DDC Decision Maker computes minimum cost schedules while viewing the rest of the power system as an "equivalent generator" whose incremental costs are specified by the

price curves provided by the EMS Decision Maker.

The DDC Decision Maker uses the optimum solution to compute either Quantity Targets or Price Curves which are sent to the DSG Decision Maker. Note that it is possible for the EMS-DDC decomposition to be Quantity Directed while the DDC-DSG decomposition is Price Directed and vice versa.

6.8 DSG Decision Maker

The DSG Decision Maker uses its very detailed models of its own costs and capability to either hit the Quantity Targets or optimize using the Price Curves provided by the DDC Decision Maker.

7. Four-Level Decomposition: Utility-Owned DSG

Figure 2 of Section 2 is a four-level decomposition which extends the ideas of Figure 1 by including a Distribution Automation Control Center (DAC) level between the DSG and DDC.

The introduction of the DAC provides very little change in any of the basic concepts. It merely allows another level of information processing, aggregation, decision making to occur. The introduction of the DAC can be very worthwhile in terms of communication links, distributed computation, etc. However relative to economic scheduling, neither level of decomposition has any inherent value over the other. In fact relative to economic scheduling, a simple two level design (no DDC or DAC between EMS and DSG) could be desirable in some cases. The choice of level and degree (e.g. how many DDC if any) of decomposition should be determined by factors other than economic scheduling. After the level and degree of decomposition has been chosen, the economic scheduling can be readily adapted to it.

8. Customer Owned DSG

Figure 3 of Section 2 is a three level decomposition like Figure 1 which was discussed in Section 6., However in Figure 3, the customer owns the DSG. Three cases are discussed:

- Nonschedulable DSG
- Schedulable DSG; Customer Gives Utility Scheduling Rights
- Schedulable DSG: Customer Does Own Scheduling

If the DSG is a nonschedulable unit such as solar, wind or run of river hydro, nothing is really changed by customer ownership. The discussions of Section 6 apply equally well.

If the DSG is scheduled and if the customer gives the utility scheduling rights little changes from the discussions of Section 6. The real problems are the complications of trying to arrive at an appropriate contractual relationship agreeable to both sides. The contractual realtionship might impose many constraints on how the utility can schedule the DSG. The number of possible contractual relationships is large. However none seem to introduce any difficult scheduling problems.

If the customer does not give the utility scheduling rights, the unit is scheduled entirely on the basis of the customer's own desires. In such a case the presence or absence of the DSG unit need be of no consideration at all to the DDC or EMS. Its effect is viewed entirely as negative load and treated exactly like the effects of wind or solar generation on "effective load" as discussed in Section 6.2. If spot pricing is used (see next section) the statistical model for effective load has to include price as an exogenous signal as well as time and weather. Random outages of the DSG unit and/or the need of backup power by the unit from the utility in case of outages are not of concern.

9. DSG Economics

This report is concerned with economic scheduling of DSG units, not with their overall economics. However it is important to understand how economic scheduling can affect the economics of installing and operating DSG units.

When the utility owns the DSG units they can be scheduled in a very good approximation to global economic efficiency as discussed in Sections 6 and 7. The cost of installing and operating the scheduling system and any economic losses due to "non perfect optimization" are small compared to the total capital and fuel costs. Therefore the scheduling system design has little effect on any economic decisions relative to DSG installation.

When the customer owns the DSG unit as discussed in Section 8, the situation can be quite different. Global economic efficiency now refers to both the utility's costs and the concerns of the customers for three types of costs:

- Fuel Costs: Paid by customer to run the DSG unit
- Utility Payments: Paid by customer to utility for electric energy as determined by rate structure. (Could be negative if customer sells electric energy back to the utility).
- Demand Rescheduling Costs: Effect of rescheduling customer electric usage patterns and/or amounts in response to fuel costs and utility payments.

Following the discussions of Section 8, two types of economic scheduling are considered:

- Customer gives utility scheduling rights
- Customer does own scheduling

If customer gives the utility scheduling rights, the conceptually optimum approach would be for the customer to give the utility all the necessary information on fuel and load/demand rescheduling costs and then let the utility schedule the operation of the DSG unit and reschedule the customer's electric usage keeping in mind the costs of all of the rest of the DSG units, customers, and central station power plants in the whole EMS service territory. The customer's utility payments would then be determined by the actual utility costs (fuel, capital, etc.). The major problem with this conceptual approach is, of course, that it requires the utility to become deeply involved in the customer's business, lifestyles, priorities, etc. It puts the utility in the undesirable position of "playing big brother" to the customer. This is bad for both the customer and the utility and is very unlikely to occur. An alternate approach is for the utility to schedule the DSG independent of the customer's needs. This is feasible but could lead to large inefficiencies relative to the customer's concerns.

Now consider the case where the customer does the scheduling (beind the meter). Price Directed decomposition as discussed in Section 5 provides an approach which can still approximate global efficiency (for both utility and customer concerns) while maintaining customer independence in scheduling decisions. The approach is to establish a rate structure based on "spot pricing". The spot price, which varies every five minutes, determines the rates ($ per kWH) for the customers to buy and/or sell electric energy from/to the utility. This spot price is directly related to the pricing signal sent by the EMS to the DDC and by the DDC to the utility owned DSG under Price Directed decomposition as discussed in Section 6. With this

approach the rates the customer pays to buy and sell back power from the utility are directly related to the actual system lambda and other system conditions. The customer optimizes the scheduling of the DSG unit relative to the utility provided spot price and the customer's knowledge of own fuel costs and demand rescheduling costs. Hence an approximation to global efficiency can be achieved without utility involvement in the "customer's business"; e.g. without crossing the meter line.

It is important to emphasize the difference between spot pricing rates and the various types of rates in use and being considered today such as block rates, hour use charges, demand charges, backup power charges, rachet clauses, and of course the time of use (TOU) variations on these ideas which allow for time of day, seasonal, etc. variations. These prespecified rates can be interpreted as attempts to give the customers "pricing signals" which reflect the average or expected costs. In practice there may be major differences between the actual costs that occur in day to day, hourly operation and those given by prespecified rates. For example with prespecified rates the customer c ould not react to outages of large central station nuclear or coal plants or to the effects of macroweather variations on total demand and wind and solar generation. Quite often the customer will not even react in an efficient fashion to the normal daily load cycles. If the difference between the average expected and actual costs are sufficiently large then it is very important for the efficiency of DSG operation that the customers be provided with spot pricing signals (i.e. a price directed decomposed economic scheduling).

The key point of the proceeding discussion is that the scheduling relationship between the utility and customers can be critical in determining the economic viability of the DSG unit if the customer owns the unit. If the customer gives the utility the scheduling rights the

customers may not gain enough returns on the capital investment to justify installing the DSG. If the customer maintains the scheduling rights, and if a prespecified rate structure between utility and customers is used, the resulting inefficiencies may cause the utility rates to be so restrictive (too high when customer buys, too low when customer sells) that the customer cannot justify installing the DSG. One approach which can eleviate this potential dilemna is the use of a spot pricing rate structure.

10. Research-Development Needs

Two problem areas associated with DSG economic scheduling which might require research are

- Modeling-prediction of macroweather patterns
- Development of stochastic unit commitment logics

These research areas could become important only if there is major penetration of solar and/or wind DSG units. Since various commercial companies are presently will[illegible] provide utilities with macroweather forecasting services tailored to economic scheduling, a research effort will be required only if this presently available methodology is not good enough. If it turns out that macroweather predictions inherently have large uncertainties, some research on stochastic unit commitment logics will be required so that the scheduling is done on a probabilistic basis which explicitly takes into account the macroweather uncertainties. However, there are no major unsurmountable obstacles seen in either of these research areas. As discussed in Section 6, macroweather modeling is a function of the EMS Information Processor. Stochastic unit commitment logics will probably be employed, if at all, by the EMS Decision Maker. The DDC Decision Maker probably will not employ such a sophisticated technique.

Another area which would require research is the choice of specific philosophies and algorithms for the computation of spot pricing if that approach to dealing with customer owned DSG is chosen. The basic principles are clear but financial, regulatory issues as well as fundamental economic philosophy (e.g., imbedded vs. marginal cost pricing) have to be addressed.

The rest of the modeling algorithmic work required for the information processing-decision making aspects of DSG economic scheduling is in the category of development rather than research. The actual development of

details, operational software, and displays etc. is not a trivial task but it is straightforward. The methodologies and techniques are well established.